niagara peninsula energy inc.
Your Local Utility

EXHIBIT 2

RATE BASE

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Exhibit 2: Rate Base

Tab 1 (of 3): Overview

OVERVIEW

2.1.1 Overview of Rate Base

This exhibit provides NPEI's distribution rate base forecast for the 2021 Test Year. It also provides an explanation of variances between 2015 Board approved figures, 2015 through 2019 actuals, 2020 Bridge Year and the 2021 Test Year.

NPEI is seeking approval in this Application for 2021 electricity distribution rates effective January 1, 2021. The rate base used to determine the 2021 Test Year revenue requirement follows Chapter 2 of the *Filing Requirements for Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications*, issued July 12, 2018 and the *Addendum to Filing Requirements for Electricity Distribution Rate Applications – 2020 Rate Applications*, issued July 15, 2019. In accordance with Section 2.2.1.1 of the Filing Requirements, NPEI has calculated its rate base for the 2021 Test Year as the average of the opening and closing balances of net capital assets plus a working capital allowance. Net capital assets are gross assets in service minus accumulated depreciation and contributed capital from third parties.

Capital assets include property, plant and equipment and intangible assets. These have been referred to "capital" or "fixed" assets throughout this evidence. Distribution assets refer to assets that are used to convey electricity throughout the distribution area, and includes poles, wires and transformers. General Plant assets support the distribution system and includes office equipment, computer hardware and software, vehicles and buildings.

NPEI's distribution assets include the Kalar Transformer Station, which Niagara Falls Hydro put into service in 2004. The Kalar TS assets were approved by the Board in Niagara Falls Hydro's 2006 EDR Application (EB-2005-0394) to be deemed distribution assets.

Section 2.2.1.3 of the Filing Requirements states:

"The commodity price estimate used to calculate the CoP must be determined by the split between RPP and non-RPP Class A and Class B customers based on actual data and using the most current RPP (TOU) prices established for the May 1, 2019 to October 31, 2019 period. The calculation must fully consider all other impacts resulting from the Ontario Fair Hydro Plan Act, 2017 (Fair Hydro Plan) as described in the OEB report Regulated Price Plan and Global Adjustment Modifier for the Period May 1, 2019 to October 31, 2019. Distributors must complete Appendix 2-Z – Commodity Expense.

In consideration of the impact of the Fair Hydro Plan, Non-RPP actual data must be split between Class A and Class B customers (RPP and Non-RPP). Non-RPP Class B consumption data must further be split between customers eligible for the Global Adjustment (GA) modifier vs. non-eligible. The GA modifier must be applied to eligible customers and a weighted average commodity price must be determined by the split between RPP, eligible non-RPP and non-eligible non-RPP customers. For customer classes that include Class A customers, a distributor must incorporate Class A GA cost by completing the relevant section in Appendix 2-Z."

On January 30, 2020, OEB Staff provided NPEI with a revised Appendix 2-Z Commodity Expense Workform, that incorporates the following changes:

- The most recent commodity rates, from the *Regulated Price Plan Price Report November 1, 2019 to October 31, 2020,* issued October 22, 2019.
- The GA Modifier was discontinued effective November 1, 2019.
- The 31.8% Ontario Electricity Rebate ("OER"), which became effective November 1, 2019, has been incorporated into the Cost of Power calculation.

In completing Appendix 2-Z, NPEI used its 2018 actual consumption data to determine the splits between RPP, Class A Non-RPP and Class B Non-RPP consumption.

The OEB's Appendix 2-Z is included as Appendix 2-2 to this Exhibit.

Table 2.1.1.1 below provides a summary of NPEI's Rate Base for 2015 Board Approved, 2015-2019 Actual, the 2020 Bridge Year and the 2021 Test Year.

Table 2.1.1.1 – Summary of Rate Base

Description	2015 Settlement WAC 13%	2015 Board Approved WAC 10.48%	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge	2021 Test	Variance 2021 Test vs. 2015 Board-Approved
Gross Fixed Assets	275,337,932	275,337,932	277,718,817	292,411,388	306,355,532	320,005,612	336,175,261	353,457,606	370,835,204	95,497,272
Accumulated Depreciation	(133,513,838)	(133,513,838)	(133,353,402)	(139,090,311)	(145,263,088)	(151,478,242)	(158,593,945)	(166,536,274)	(174,413,867)	(40,900,030)
Gross Capital Contributions	(23,814,201)	(23,814,201)	(28,054,750)	(32,086,201)	(34,557,685)	(37,095,719)	(42,558,399)	(46,412,572)	(48,995,800)	(25,181,599)
Accumulated Amortization of Capital Contributions	8,042,651	8,042,651	7,463,406	8,201,844	9,026,035	9,920,039	10,922,804	12,049,613	13,261,201	5,218,550
Net Book Value	126,052,544	126,052,544	123,774,070	129,436,720	135,560,794	141,351,691	145,945,721	152,558,373	160,686,738	34,634,194
Average Net Book Value	123,133,488	123,133,488	121,994,251	126,605,395	132,498,757	138,456,243	143,648,706	149,252,047	156,622,556	33,489,067
Working Capital	160,574,664	160,574,664	167,717,596	182,815,582	164,694,955	155,547,319	165,517,410	171,534,673	177,728,664	17,154,000
Working Capital Allowance %	13.00%	10.48%	10.48%	10.48%	10.48%	10.48%	10.48%	10.48%	7.5%	-2.98%
Working Capital Allowance	20,874,706	16,828,225	17,576,804	19,159,073	17,260,031	16,301,359	17,346,225	17,976,834	13,329,650	(3,498,575)
Rate Base	**144,008,195**	**139,961,713**	**139,571,055**	**145,764,468**	**149,758,789**	**154,757,602**	**160,994,930**	**167,228,881**	**169,952,205**	**29,990,492**

NPEI has calculated its Rate Base for the 2021 Test Year as $169,952,205, which represents an average annual increase of $5.0M over 2015 Board-Approved.

The proposed Rate Base for 2021 consists of an average net book value of $156.6M in Property, Plant and Equipment and $13.3M in Working Capital Allowance. The 2021 Test Year Rate Base is $30.0M greater than NPEI's 2015 Board Approved Rate Base. The increase in Rate Base is due to the following factors:

1. An increase in average net book value of capital assets of $34.6M, which consists of:
   a. An increase in gross fixed assets of $95.5M, partially offset by an increase in accumulated amortization of ($40.9M).
   b. An increase in gross capital contributions of ($25.2M), partially offset by an increase in accumulated amortization of capital contributions of $5.2M.
2. A decrease in working capital allowance of $3.5M, which consists of:
   a. An increase in working capital (Cost of Power plus OM&A expenses) of $17.2M
   b. A decrease in the working capital allowance percentage of (2.98%).

Year over year variance analysis of rate base is provided below.

Table 2.1.1.2 – 2015 Actual vs 2015 Board Approved

Description	2015 Board Approved	2015 Actual	Variance $	Variance %
Gross Fixed Assets	275,337,932	277,718,817	2,380,885	0.9%
Accumulated Depreciation	(133,513,838)	(133,353,402)	160,435	-0.1%
Gross Capital Contributions	(23,814,201)	(28,054,750)	(4,240,550)	17.8%
Accumulated Amortization of Capital Contributions	8,042,651	7,463,406	(579,245)	-7.2%
Net Book Value	126,052,544	123,774,070	(2,278,474)	-1.8%
Average Net Book Value	123,133,488	121,994,251	(1,139,237)	-0.9%
Working Capital	160,574,664	167,717,596	7,142,932	4.4%
Working Capital Allowance %	10.48%	10.48%	0.00%	0.0%
Working Capital Allowance	16,828,225	17,576,804	748,579	4.4%
Rate Base	**139,961,713**	**139,571,055**	**(390,658)**	**-0.3%**

2015 Actual rate base was ($390,658) or (0.3%) lower than 2015 Board Approved due to:

1. A decrease in average net book value of capital assets of ($1,139K) which consists of:
    a. An increase in gross fixed assets of $2,381K and a decrease in accumulated depreciation of $160K.
    b. An increase in gross capital contributions of ($4,241K) and a decrease in accumulated amortization of capital contributions of ($579K)
2. An increase in working capital allowance of $749K, which consists of:
    a. An increase in Cost of Power of $6,694K or 4.6%.
    b. An increase in OM&A expense of $448K or 2.7%.

Table 2.1.1.3 – 2016 Actual vs 2015 Actual

Description	2015 Actual	2016 Actual	Variance $	Variance %
Gross Fixed Assets	277,718,817	292,411,388	14,692,571	5.3%
Accumulated Depreciation	(133,353,402)	(139,090,311)	(5,736,909)	4.3%
Gross Capital Contributions	(28,054,750)	(32,086,201)	(4,031,451)	14.4%
Accumulated Amortization of Capital Contributions	7,463,406	8,201,844	738,438	9.9%
Net Book Value	123,774,070	129,436,720	5,662,650	4.6%
Average Net Book Value	121,994,251	126,605,395	4,611,144	3.8%
Working Capital	167,717,596	182,815,582	15,097,986	9.0%
Working Capital Allowance %	10.48%	10.48%	0.00%	0.0%
Working Capital Allowance	17,576,804	19,159,073	1,582,269	9.0%
Rate Base	**139,571,055**	**145,764,468**	**6,193,413**	**4.4%**

2016 Actual rate base was $6,193K or 4.4% higher than 2015 Actual due to:

1. An increase in average net book value of capital assets of $5,663K which consists of:
    a. An increase in gross fixed assets of $14,693K partially offset by an increase in accumulated depreciation of ($5,737K).
    b. An increase in gross capital contributions of ($4,031K) partially offset by an increase in accumulated amortization of capital contributions of $738K.
2. An increase in working capital allowance of $1,582K, which consists of:
    a. An increase in Cost of Power of $14,825K or 9.8%.
    b. An increase in OM&A expense of $273K or 1.6%.

Table 2.1.1.4 – 2017 Actual vs 2016 Actual

Description	2016 Actual	2017 Actual	Variance $	Variance %
Gross Fixed Assets	292,411,388	306,355,532	13,944,144	4.8%
Accumulated Depreciation	(139,090,311)	(145,263,088)	(6,172,777)	4.4%
Gross Capital Contributions	(32,086,201)	(34,557,685)	(2,471,484)	7.7%
Accumulated Amortization of Capital Contributions	8,201,844	9,026,035	824,191	10.0%
Net Book Value	129,436,720	135,560,794	6,124,074	4.7%
Average Net Book Value	126,605,395	132,498,757	5,893,362	4.7%
Working Capital	182,815,582	164,694,955	(18,120,627)	-9.9%
Working Capital Allowance %	10.48%	10.48%	0.00%	0.0%
Working Capital Allowance	19,159,073	17,260,031	(1,899,042)	-9.9%
Rate Base	**145,764,468**	**149,758,789**	**3,994,320**	**2.7%**

2017 Actual rate base was $3,994K or 2.7% higher than 2016 Actual due to:

1. An increase in average net book value of capital assets of $5,893K which consists of:
    a. An increase in gross fixed assets of $13,944K partially offset by an increase in accumulated depreciation of ($6,173K).
    b. An increase in gross capital contributions of ($2,471K) partially offset by an increase in accumulated amortization of capital contributions of $824K.
2. A decrease in working capital allowance of ($1,895K), which consists of:
    a. A decrease in Cost of Power of ($19,243K) or (11.6%).
    b. An increase in OM&A expense of $1,122K or 6.5%.

Table 2.1.1.5 – 2018 Actual vs 2017 Actual

Description	2017 Actual	2018 Actual	Variance $	Variance %
Gross Fixed Assets	306,355,532	320,005,612	13,650,080	4.5%
Accumulated Depreciation	(145,263,088)	(151,478,242)	(6,215,154)	4.3%
Gross Capital Contributions	(34,557,685)	(37,095,719)	(2,538,034)	7.3%
Accumulated Amortization of Capital Contributions	9,026,035	9,920,039	894,004	9.9%
Net Book Value	135,560,794	141,351,691	5,790,896	4.3%
Average Net Book Value	132,498,757	138,456,243	5,957,485	4.5%
Working Capital	164,694,955	155,547,319	(9,147,636)	-5.6%
Working Capital Allowance %	10.48%	10.48%	0.00%	0.0%
Working Capital Allowance	17,260,031	16,301,359	(958,672)	-5.6%
Rate Base	**149,758,789**	**154,757,602**	**4,998,813**	**3.3%**

2018 Actual rate base was $4,999K or 3.3% higher than 2017 Actual due to:

1. An increase in average net book value of capital assets of $5,957K which consists of:
    a. An increase in gross fixed assets of $13,650K partially offset by an increase in accumulated depreciation of ($6,215K).
    b. An increase in gross capital contributions of ($2,538K) partially offset by an increase in accumulated amortization of capital contributions of $894K.
2. A decrease in working capital allowance of ($959K), which consists of:
    a. A decrease in Cost of Power of ($8,900K) or (6.1%).
    b. A decrease in OM&A expense of ($248K) or (1.4%).

Table 2.1.1.6 – 2019 Actual vs 2018 Actual

Description	2018 Actual	2019 Actual	Variance $	Variance %
Gross Fixed Assets	320,005,612	336,175,261	16,169,649	5.1%
Accumulated Depreciation	(151,478,242)	(158,593,945)	(7,115,703)	4.7%
Gross Capital Contributions	(37,095,719)	(42,558,399)	(5,462,680)	14.7%
Accumulated Amortization of Capital Contributions	9,920,039	10,922,804	1,002,764	10.1%
Net Book Value	141,351,691	145,945,721	4,594,030	3.3%
Average Net Book Value	138,456,243	143,648,706	5,192,463	3.8%
Working Capital	155,547,319	165,517,410	9,970,091	6.4%
Working Capital Allowance %	10.48%	10.48%	0.00%	0.0%
Working Capital Allowance	16,301,359	17,346,225	1,044,865	6.4%
Rate Base	**154,757,602**	**160,994,930**	**6,237,329**	**4.0%**

2019 Actual rate base was $6,237K or 4.0% higher than 2018 Actual due to:

1. An increase in average net book value of capital assets of $5,192K which consists of:
    a. An increase in gross fixed assets of $16,170K partially offset by an increase in accumulated depreciation of ($7,116K).
    b. An increase in gross capital contributions of ($5,463K) partially offset by an increase in accumulated amortization of capital contributions of $1,003K.
2. An increase in working capital allowance of $1,045K, which consists of:
    a. An increase in Cost of Power of $8,832K or 6.4%.
    b. An increase in OM&A expense of $1,138K or 6.3%.

Table 2.1.1.7 – 2020 Bridge vs 2019 Actual

Description	2019 Actual	2020 Bridge	Variance $	Variance %
Gross Fixed Assets	336,175,261	353,457,606	17,282,345	5.1%
Accumulated Depreciation	(158,593,945)	(166,536,274)	(7,942,329)	5.0%
Gross Capital Contributions	(42,558,399)	(46,412,572)	(3,854,173)	9.1%
Accumulated Amortization of Capital Contributions	10,922,804	12,049,613	1,126,809	10.3%
Net Book Value	145,945,721	152,558,373	6,612,652	4.5%
Average Net Book Value	143,648,706	149,252,047	5,603,341	3.9%
Working Capital	165,517,410	171,534,673	6,017,263	3.6%
Working Capital Allowance %	10.48%	10.48%	0.00%	0.0%
Working Capital Allowance	17,346,225	17,976,834	630,609	3.6%
Rate Base	**160,994,930**	**167,228,881**	**6,233,950**	**3.9%**

The 2020 Bridge Year rate base is $6,234K or 3.9% higher than 2019 Actual due to:

1. An increase in average net book value of capital assets of $5,603K which consists of:
    a. An increase in gross fixed assets of $17,282K partially offset by an increase in accumulated depreciation of ($7,942K).
    b. An increase in gross capital contributions of ($3,854K) partially offset by an increase in accumulated amortization of capital contributions of $1,127K.
2. An increase in working capital allowance of $631K, which consists of:
    a. An increase in Cost of Power of $5,553K or 3.8%.
    b. An increase in OM&A expense of $465K or 2.4%.

Table 2.1.1.8 – 2021 Test vs 2020 Bridge

Description	2020 Bridge	2021 Test	Variance $	Variance %
Gross Fixed Assets	353,457,606	370,835,204	17,377,598	4.9%
Accumulated Depreciation	(166,536,274)	(174,413,867)	(7,877,593)	4.7%
Gross Capital Contributions	(46,412,572)	(48,995,800)	(2,583,228)	5.6%
Accumulated Amortization of Capital Contributions	12,049,613	13,261,201	1,211,588	10.1%
Net Book Value	152,558,373	160,686,738	8,128,365	5.3%
Average Net Book Value	149,252,047	156,622,556	7,370,509	4.9%
Working Capital	171,534,673	177,728,664	6,193,991	3.6%
Working Capital Allowance %	10.48%	7.5%	-2.98%	-28.4%
Working Capital Allowance	17,976,834	13,329,650	(4,647,184)	-25.9%
Rate Base	**167,228,881**	**169,952,205**	**2,723,325**	**1.6%**

NPEI's proposed 2021 Test Year rate base is $2,723K or 1.6% higher than the 2020 Bridge Year due to:

1. An increase in average net book value of capital assets of $7,371K which consists of:
   a. An increase in gross fixed assets of $17,378K partially offset by an increase in accumulated depreciation of ($7,878K).
   b. An increase in gross capital contributions of ($2,583K) partially offset by an increase in accumulated amortization of capital contributions of $1,212K.
2. A decrease in working capital allowance of ($4,647K), which consists of:
   a. An increase in Cost of Power of $5,433K or 3.6%.
   b. An increase in OM&A expense of $760K or 3.9%.
   c. A decrease in Working Capital Allowance Percentage from 10.48% to 7.5%.

Further details of capital asset variances are provided in Exhibit 2.1.2 and Exhibit 2.2.2. Further details of OM&A expense variances are provided in Exhibit 4.

NPEI has completed Appendix 2-BA for 2015-2019 Actual, the 2020 Bridge Year and the 2021 Test Year, which is included as Appendix 2-1 to this Exhibit.

The schedules in Appendix 2-BA present a continuity schedule of NPEI's investment in capital assets, and the associated accumulated depreciation by Uniforms System of Accounts (USoA) account number.

NPEI adopted Modified International Financial Reporting Standards (MIFRS) in 2015. The continuity schedules for each year in Appendix 2-BA have all been completed on a MIFRS basis.

GROSS ASSETS (PP&E)

2.1.2 Gross Assets (PP&E)

For the purpose of providing breakdown by function, NPEI utilized the following classifications: Land and Buildings, Transformer and Distribution Stations, Poles and Wires, Line Transformers, Services and Meters, IT Assets, Equipment and Intangible Assets.

Land and Buildings include USoA accounts 1805 Land, 1808 Buildings, 1905 Land, 1908 Buildings and 1910 Leasehold Improvements.

Transformer and Distribution Stations include USoA accounts 1815 Transformer Station Equipment and 1820 Distribution Station Equipment.

Poles and Wires includes USoA accounts 1830 Poles, Towers and Fixtures, 1835 Overhead Conductors and Devices, 1840 Underground Conduit and 1845 Underground Conductors and Devices.

Line Transformers includes USoA account 1850 Line Transformers.

Services and Meters includes USoA accounts 1855 Services and 1860 Meters.

IT Assets includes USoA account 1920 Computer Equipment – Hardware.

Equipment includes USoA accounts 1915 Office Furniture and Equipment, 1930 Transportation Equipment, 1935 Stores Equipment, 1940 Tools Shop and Garage Equipment, 1945 Measurement and Testing Equipment, 1955 Communication Equipment, 1960 Miscellaneous Equipment and 1980 System Supervisory Equipment.

Intangible Assets includes USoA accounts 1611 Computer Software and 1612 Land Rights.

Table 2.1.2.1 below provides a summary of gross assets by function for 2015 Board Approved, 2015-2019 Actual, the 2020 Bridge Year and the 2021 Test Year.

Table 2.1.2.1 – Gross Assets by Function

UsoA	Description	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge	2021 Test
	Land & Buildings								
1805	Land	507,273	507,273	507,273	507,273	507,273	507,273	507,273	507,273
1808	Buildings	111,638	111,638	111,638	111,638	111,638	111,638	111,638	111,638
1905	Land	508,970	508,970	508,970	508,970	508,970	508,970	508,970	508,970
1908	Buildings	16,801,173	17,199,162	17,251,916	17,654,923	18,679,787	20,717,683	22,485,783	22,721,283
1910	Leasehold Improvements	120,252	120,252	120,252	120,252	120,252	120,252	120,252	120,252
	Sub-total	18,049,306	18,447,296	18,500,049	18,903,056	19,927,920	21,965,816	23,733,916	23,969,416
	Transformer & Distribution Stations								
1815	Transformer Station Equipment	6,651,424	6,652,803	6,652,803	6,709,755	6,845,044	7,044,289	7,119,289	8,818,886
1820	Distribution Station Equipment	6,859,037	6,867,626	6,867,626	7,105,405	6,969,921	7,119,637	7,119,637	7,119,637
	Sub-total	13,510,461	13,520,429	13,520,429	13,815,161	13,814,965	14,163,926	14,238,926	15,938,523
	Poles & Wires								
1830	Poles, Towers & Fixtures	47,602,574	47,375,180	50,036,956	52,203,372	54,187,733	55,827,640	58,101,314	61,437,851
1835	Overhead Conductors & Devices	31,331,004	32,112,730	34,575,301	36,694,266	39,044,434	40,965,809	43,039,853	45,085,446
1840	Underground Conduit	12,120,570	11,140,555	12,338,449	13,214,100	14,270,567	14,778,417	17,238,359	19,542,266
1845	Underground Conductors & Devices	71,147,319	73,603,818	77,412,749	80,230,387	82,442,652	85,815,272	90,259,889	93,361,252
	Sub-total	162,201,467	164,232,284	174,363,455	182,342,124	189,945,387	197,387,137	208,639,416	219,426,816
	Line Transformers								
1850	Line Transformers	40,155,386	40,618,575	42,126,350	43,637,990	45,434,847	47,947,933	49,123,794	50,680,361
	Sub-total	40,155,386	40,618,575	42,126,350	43,637,990	45,434,847	47,947,933	49,123,794	50,680,361
	Services & Meters								
1855	Services	7,122,402	7,282,470	8,465,325	9,793,963	11,110,941	12,779,084	14,097,983	15,534,443
1860	Meters	9,783,863	9,869,131	10,358,693	11,125,932	12,029,941	12,776,483	13,535,443	14,067,093
	Sub-total	16,906,265	17,151,601	18,824,018	20,919,895	23,140,881	25,555,567	27,633,426	29,601,537
	IT Assets								
1920	Computer Equipment Hardware	4,293,075	4,305,894	4,547,111	4,879,232	5,202,743	5,395,892	5,565,992	5,904,772
	Sub-total	4,293,075	4,305,894	4,547,111	4,879,232	5,202,743	5,395,892	5,565,992	5,904,772
	Equipment								
1915	Office Furniture & Equipment	1,684,388	1,695,777	1,723,808	1,741,871	1,856,959	1,941,662	2,035,962	2,115,062
1930	Transportation Equipment	9,180,229	8,778,183	9,074,202	9,666,390	9,762,133	10,321,378	10,484,525	10,720,468
1935	Stores Equipment	284,057	323,279	323,279	323,279	328,495	328,495	328,495	328,495
1940	Tools, Shop & Garage Equipment	2,083,142	2,081,942	2,200,663	2,289,678	2,355,710	2,447,550	2,512,250	2,589,550
1945	Measurement & Testing Equipment	205,006	204,006	204,006	204,006	204,006	204,006	204,006	204,006
1955	Communications Equipment	1,319,926	1,140,929	1,442,918	1,360,855	1,470,680	1,593,239	1,693,239	1,818,239
1960	Miscellaneous Equipment	73,951	72,951	72,951	72,951	72,951	72,951	72,951	72,951
1980	System supervisor Equipment	128,961	128,961	128,961	128,961	128,961	128,961	128,961	128,961
	Sub-total	14,959,660	14,426,028	15,170,788	15,787,990	16,179,895	17,038,242	17,460,389	17,977,732
	Intangible Assets								
1611	Computer Software	3,657,915	3,412,315	3,754,792	4,465,687	4,754,578	5,116,351	5,457,351	5,731,651
1612	Land Rights	1,604,397	1,604,397	1,604,397	1,604,397	1,604,397	1,604,397	1,604,397	1,604,397
	Sub-total	5,262,312	5,016,711	5,359,188	6,070,084	6,358,975	6,720,747	7,061,747	7,336,047
	Total - Gross Assets	**275,337,932**	**277,718,817**	**292,411,388**	**306,355,532**	**320,005,612**	**336,175,261**	**353,457,606**	**370,835,204**
	Capital Contributions								
2440	Deferred Revenue	(23,814,507)	(28,054,750)	(32,086,201)	(34,557,685)	(37,095,719)	(42,558,399)	(46,412,572)	(48,995,800)
	Sub-total	(23,814,507)	(28,054,750)	(32,086,201)	(34,557,685)	(37,095,719)	(42,558,399)	(46,412,572)	(48,995,800)
	Total - Gross Assets Net of Capital Contributions	**251,523,425**	**249,664,067**	**260,325,187**	**271,797,847**	**282,909,893**	**293,616,862**	**307,045,034**	**321,839,404**

Variance Analysis

Year-over-year variance analysis of gross fixed assets is provided below. For the purpose of this analysis, NPEI has used a materiality threshold of $170K.

Table 2.1.2.2 – Materiality Threshold

Service Revenue Requirement	37,840,675
(from Revenue Deficiency Calculation)	
Less Revenue Offsets	(2,971,337)
Base Revenue Requirement	**34,869,338**
Variance Calculation 0.5% of Distribution Revenue Requirement	**$ 174,347**

Table 2.1.2.3 – 2015 Actual vs. 2015 Board Approved

UsoA	Description	2015 Board Approved	2015 Actual	Variance $
	Land & Buildings			
1805	Land	507,273	507,273	(0)
1808	Buildings	111,638	111,638	0
1905	Land	508,970	508,970	(0)
1908	Buildings	16,801,173	17,199,162	397,989
1910	Leasehold Improvements	120,252	120,252	0
	Sub-total	18,049,306	18,447,296	397,990
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	6,651,424	6,652,803	1,379
1820	Distribution Station Equipment	6,859,037	6,867,626	8,589
	Sub-total	13,510,461	13,520,429	9,968
	Poles & Wires			
1830	Poles, Towers & Fixtures	47,602,574	47,375,180	(227,394)
1835	Overhead Conductors & Devices	31,331,004	32,112,730	781,726
1840	Underground Conduit	12,120,570	11,140,555	(980,015)
1845	Underground Conductors & Devices	71,147,319	73,603,818	2,456,499
	Sub-total	162,201,467	164,232,284	2,030,817
	Line Transformers			
1850	Line Transformers	40,155,386	40,618,575	463,189
	Sub-total	40,155,386	40,618,575	463,189
	Services & Meters			
1855	Services	7,122,402	7,282,470	160,068
1860	Meters	9,783,863	9,869,131	85,268
	Sub-total	16,906,265	17,151,601	245,336
	IT Assets			
1920	Computer Equipment Hardware	4,293,075	4,305,894	12,819
	Sub-total	4,293,075	4,305,894	12,819
	Equipment			
1915	Office Furniture & Equipment	1,684,388	1,695,777	11,389
1930	Transportation Equipment	9,180,229	8,778,183	(402,046)
1935	Stores Equipment	284,057	323,279	39,222
1940	Tools, Shop & Garage Equipment	2,083,142	2,081,942	(1,200)
1945	Measurement & Testing Equipment	205,006	204,006	(1,000)
1955	Communications Equipment	1,319,926	1,140,929	(178,997)
1960	Miscellaneous Equipment	73,951	72,951	(1,000)
1980	System supervisor Equipment	128,961	128,961	(0)
	Sub-total	14,959,660	14,426,028	(533,632)
	Intangible Assets			
1611	Computer Software	3,657,915	3,412,315	(245,600)
1612	Land Rights	1,604,397	1,604,397	(0)
	Sub-total	5,262,312	5,016,711	(245,601)
	Total - Gross Assets	**275,337,932**	**277,718,817**	**2,380,885**
	Capital Contributions			
2440	Deferred Revenue	(23,814,507)	(28,054,750)	(4,240,244)
	Sub-total	(23,814,507)	(28,054,750)	(4,240,244)
	Total - Gross Assets Net of Capital Contributions	**251,523,425**	**249,664,067**	**(1,859,358)**

NPEI notes that the gross fixed asset additions and the capital contributions approved in NPEI's 2015 COS Rate Application (EB-2014-0096) do not include the cost of expansion facilities transferred from customers which were constructed under the alternative bid option, in accordance with Section 3.2 of the Distribution System Code.

In 2015, NPEI recorded $3.1M in transferred assets, with offsetting capital contributions, as follows:

Account #	Account Description	Dr	Cr
1845	Underground Conductors and Devices	2,370,239	
1853	Line Transformers	790,080	
2440	Capital Contributions - Underground		2,370,239
2440	Capital Contributions - Transformers		790,080

<u>Land and Buildings Variance $398K</u>

NPEI's 2015 COS Rate Application (EB-2014-0096) included approved 2015 additions for account 1908 Building of $87K. NPEI's 2015 actual building expenditures were $469K, which primarily consists of:

- $365K for parking lot paving
- $59K for a new ventilation system in the stores area
- $37K for gas service and heating system in the wire building

<u>Poles and Wires Variance $2,031K</u>

As noted above, $2,370K of this variance relates to expansion facilities transferred from customers. Excluding this amount, the 2015 Actual vs 2015 Board Approved total variance for Poles and Wires is ($339K), which consists of Overhead (Accounts 1830 and 1835) of $554K and Underground (Accounts 1840 and 1845) of ($894K). Several capital projects that were planned for 2015 were deferred until 2016 due to an increase in customer driven system access projects, including new commercial services, road relocation projects and new subdivisions. The projects completed in 2015 include a higher level of overhead plant, and a lower level of underground plant, compared to 2015 Board Approved.

NPEI has completed the OEB's Appendix 2-AA, which provides further details of individual project and capital program costs by year, and is included as Appendix 2-4 to this Exhibit. Descriptions of individual projects and programs for 2015-2020 are provided in Exhibit 2.2.2.

Line Transformers Variance $463K

As noted above, $790K of this variance relates to expansion facilities transferred from customers. Excluding this amount, the 2015 Actual vs 2015 Board Approved variance for Line Transformers is ($327K). This variance largely relates to disposals of ($192K) recorded in 2015 for obsolete transformers.

Services and Meters Variance $245K

Account 1855 Services is $160K higher than Board Approved, and Account 1860 Meters is $85K higher than Board Approved due to an increase in new connections.

Equipment Variance ($534K)

The 2015 Actual total for Equipment is ($534K) lower than Board Approved. The material differences are as follows:

- Transportation Equipment is ($402K) lower than Board Approved. 2015 Actual additions were lower by ($208K), and 2015 Actual disposals were greater by ($190K). The replacement of one of NPEI's bucket trucks originally scheduled for 2015 was deferred to 2016, and several small vehicles scheduled to be replaced in 2016 were completed in 2015.
- Communication Equipment is ($179K) lower than Board Approved. The Wi-Max communications project was under budget in 2015 due to staff changes in NPEI's engineering department.

Intangible Assets Variance ($246K)

The 2015 Actual total for Account 1611 Computer Software was ($246K) lower than Board Approved.

Capital Contributions Variance ($4,240K)

The 2015 Actual total for Account 2440 Deferred Revenue (Capital Contributions) was ($4,240K) higher than Board Approved. As noted above, ($3,160K) of this variance relates to expansion facilities transferred from customers. Excluding this amount, the 2015 Actual vs 2015 Board Approved variance for Capital Contributions is ($1,079K), due to an increase in customer driven system access projects, including new commercial services, road relocation projects and new subdivisions.

Table 2.1.2.4 – 2016 Actual vs. 2015 Actual

UsoA	Description	2015 Actual	2016 Actual	Variance $
	Land & Buildings			
1805	Land	507,273	507,273	-
1808	Buildings	111,638	111,638	-
1905	Land	508,970	508,970	-
1908	Buildings	17,199,162	17,251,916	52,753
1910	Leasehold Improvements	120,252	120,252	-
	Sub-total	18,447,296	18,500,049	52,753
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	6,652,803	6,652,803	-
1820	Distribution Station Equipment	6,867,626	6,867,626	-
	Sub-total	13,520,429	13,520,429	-
	Poles & Wires			
1830	Poles, Towers & Fixtures	47,375,180	50,036,956	2,661,776
1835	Overhead Conductors & Devices	32,112,730	34,575,301	2,462,572
1840	Underground Conduit	11,140,555	12,338,449	1,197,894
1845	Underground Conductors & Devices	73,603,818	77,412,749	3,808,930
	Sub-total	164,232,284	174,363,455	10,131,172
	Line Transformers			
1850	Line Transformers	40,618,575	42,126,350	1,507,775
	Sub-total	40,618,575	42,126,350	1,507,775
	Services & Meters			
1855	Services	7,282,470	8,465,325	1,182,855
1860	Meters	9,869,131	10,358,693	489,562
	Sub-total	17,151,601	18,824,018	1,672,417
	IT Assets			
1920	Computer Equipment Hardware	4,305,894	4,547,111	241,217
	Sub-total	4,305,894	4,547,111	241,217
	Equipment			
1915	Office Furniture & Equipment	1,695,777	1,723,808	28,031
1930	Transportation Equipment	8,778,183	9,074,202	296,019
1935	Stores Equipment	323,279	323,279	-
1940	Tools, Shop & Garage Equipment	2,081,942	2,200,663	118,722
1945	Measurement & Testing Equipment	204,006	204,006	-
1955	Communications Equipment	1,140,929	1,442,918	301,990
1960	Miscellaneous Equipment	72,951	72,951	-
1980	System supervisor Equipment	128,961	128,961	-
	Sub-total	14,426,028	15,170,788	744,761
	Intangible Assets			
1611	Computer Software	3,412,315	3,754,792	342,477
1612	Land Rights	1,604,397	1,604,397	-
	Sub-total	5,016,711	5,359,188	342,477
	Total - Gross Assets	**277,718,817**	**292,411,388**	**14,692,571**
	Capital Contributions			
2440	Deferred Revenue	(28,054,750)	(32,086,201)	(4,031,451)
	Sub-total	(28,054,750)	(32,086,201)	(4,031,451)
	Total - Gross Assets Net of Capital Contributions	**249,664,067**	**260,325,187**	**10,661,120**

Poles and Wires Variance $10,131K

Line Transformers Variance $1,508K

Services and Meters Variance $1,672K

Significant components of NPEI's distribution system investments in 2016 include: Customer Driven System Reinforcements and New Commercial Connections $1,980K, Subdivisions $1,396K, Relocations for Wind Farm Conflicts $1,528K, Overhead Rebuilds $2,630K, Pole Replacements $584K, Kiosk Replacements $1,166K, Switchgear Replacements $222K, Sustainment $1,089K and Transfer of Expansion Facilities from Customers $688K.

In 2014, the Ontario Energy Board provided notice of amendments to the Distribution System Code ("DSC") pursuant to section 70.2 of the Ontario Energy Board Act, 1998. The DSC amendments provide notice that a distributor is required to install an interval meter (i.e. a "MIST" meter) on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW. The DSC requires that MIST meters are to be installed by August 21, 2020. NPEI's 2015 COS Rate Application (EB-2014-0096) included an estimate of 915 conventional meters to be replaced between 2015 and 2020. During 2016, NPEI replaced 108 conventional meters with MIST meters.

NPEI has completed the OEB's Appendix 2-AA, which provides further details of individual project and capital program costs by year, and is included as Appendix 2-4 to this Exhibit. Descriptions of individual projects and programs for 2015-2020 are provided in Exhibit 2.2.2.

IT Assets Variance $241K

Computer Hardware additions for 2016 include: 2 new servers, integration of the phone system to the CIS/Outage Management System and virtual environment conversion.

Equipment Variance $745K

Equipment expenditures for 2016 include:

- Replacement of 2 pick-up trucks for $75K, replacement of a 1996 46' Material

Handler and a 1993 Radial Boom Derrick for a total of $643K, and the purchase of a Bobcat skid steer loader for $75K. Vehicle disposals for 2016 are ($499K).

- Communication Equipment additions of $302K, which includes the design and construction of a new communications tower at Campden DS.

Intangible Assets Variance $342K

Computer Software additions for 2016 include: second layer malware, SQL server licensing, automated voice callback software, Work Management / Outage Management software, Northstar CIS upgrades and virtual environment conversion.

Capital Contributions Variance ($4,031K)

Capital contributions recorded in 2016 include: ($1,658K) for relocations due to Wind Farm conflicts, ($1,145K) for new subdivisions and ($688K) for expansion facilities transferred from customers.

1 **Table 2.1.2.5 – 2017 Actual vs. 2016 Actual**

UsoA	Description	2016 Actual	2017 Actual	Variance $
	Land & Buildings			
1805	Land	507,273	507,273	-
1808	Buildings	111,638	111,638	-
1905	Land	508,970	508,970	-
1908	Buildings	17,251,916	17,654,923	403,007
1910	Leasehold Improvements	120,252	120,252	-
	Sub-total	18,500,049	18,903,056	403,007
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	6,652,803	6,709,755	56,952
1820	Distribution Station Equipment	6,867,626	7,105,405	237,780
	Sub-total	13,520,429	13,815,161	294,732
	Poles & Wires			
1830	Poles, Towers & Fixtures	50,036,956	52,203,372	2,166,416
1835	Overhead Conductors & Devices	34,575,301	36,694,266	2,118,964
1840	Underground Conduit	12,338,449	13,214,100	875,650
1845	Underground Conductors & Devices	77,412,749	80,230,387	2,817,639
	Sub-total	174,363,455	182,342,124	7,978,669
	Line Transformers			
1850	Line Transformers	42,126,350	43,637,990	1,511,640
	Sub-total	42,126,350	43,637,990	1,511,640
	Services & Meters			
1855	Services	8,465,325	9,793,963	1,328,638
1860	Meters	10,358,693	11,125,932	767,239
	Sub-total	18,824,018	20,919,895	2,095,877
	IT Assets			
1920	Computer Equipment Hardware	4,547,111	4,879,232	332,121
	Sub-total	4,547,111	4,879,232	332,121
	Equipment			
1915	Office Furniture & Equipment	1,723,808	1,741,871	18,063
1930	Transportation Equipment	9,074,202	9,666,390	592,188
1935	Stores Equipment	323,279	323,279	-
1940	Tools, Shop & Garage Equipment	2,200,663	2,289,678	89,015
1945	Measurement & Testing Equipment	204,006	204,006	-
1955	Communications Equipment	1,442,918	1,360,855	(82,064)
1960	Miscellaneous Equipment	72,951	72,951	-
1980	System supervisor Equipment	128,961	128,961	-
	Sub-total	15,170,788	15,787,990	617,202
	Intangible Assets			
1611	Computer Software	3,754,792	4,465,687	710,896
1612	Land Rights	1,604,397	1,604,397	-
	Sub-total	5,359,188	6,070,084	710,896
	Total - Gross Assets	**292,411,388**	**306,355,532**	**13,944,144**
	Capital Contributions			
2440	Deferred Revenue	(32,086,201)	(34,557,685)	(2,471,484)
	Sub-total	(32,086,201)	(34,557,685)	(2,471,484)
	Total - Gross Assets Net of Capital Contributions	**260,325,187**	**271,797,847**	**11,472,660**

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<u>Land and Buildings Variance $403K</u>

Building expenditures in 2017 include:

- $173K for a new Wi-Max communications tower in Niagara Falls.
- The Wi-Max communications tower that was installed at Campden DS in 2016 at a cost of $115K was reclassed from Communication Equipment to Building in 2017, to more accurately reflect the estimated useful life of the tower.

<u>Transformer and Distribution Station Variance $295K</u>

During 2017, NPEI replaced a 5,000 KVA transformer at Station Street DS for $179K.

<u>Poles and Wires Variance $7,979K</u>

<u>Line Transformers Variance $1,512K</u>

<u>Services and Meters Variance $2,096K</u>

Significant components of NPEI's distribution system investments in 2017 include: Customer Driven System Reinforcements and New Commercial Connections $1,954K, Subdivisions $1,104K, Overhead Rebuilds $2,611K, Pole Replacements $1,009K, Kiosk Replacements $937K, Switchgear Replacements $205K, Sustainment $1,076K and Transfer of Expansion Facilities from Customers $902K.

The Meter variance of $767K includes the replacement of 201 interval meters which used legacy 2G cellular communication technology. In the spring of 2017, NPEI received notification from the vendor which provided intermediate communication service for these meters that they would no longer support the metering communication system due to it becoming obsolete in the cellular domain. NPEI identified 225 meters that utilized the 2G network to be replaced in order to avoid possible communication disruptions to these meters that provide energy metering to large commercial customers. NPEI completed 201 of the 2G meter changes in 2017, with the remaining 24 meter changes completed in 2018.

During 2017, NPEI replaced 102 conventional meters with MIST meters.

NPEI has completed the OEB's Appendix 2-AA, which provides further details of individual project and capital program costs by year, and is included as Appendix 2-4 to this Exhibit. Descriptions of individual projects and programs for 2015-2020 are provided in Exhibit 2.2.2.

<u>IT Assets Variance $332K</u>

Computer Hardware additions for 2017 include: 2 new nodes for hyper-convergence virtual environment conversion, network switches and the replacement of 2 plotters for engineering.

<u>Equipment Variance $617K</u>

Equipment additions for 2017 include:

- Replacement of 3 pick-up trucks and purchase of 2 electric vehicles for a total of $177K.
- Replacement of a 1993 International bucket truck and a 1989 crane for a total of $699K.
- Vehicle disposals in 2017 are ($284K).
- Communication Equipment additions are ($82K), due to the reclassification of ($115K) from Communication Equipment to Buildings for the communication tower at Campden DS.

<u>Intangible Assets Variance $711K</u>

Computer Software additions for 2017 include: Outage Management System upgrades for call taker and a mobile component, upgrade to the outage map, 2 GIS licenses, upgrade of Great Plains accounting system, enhancements to the CIS for change of contacts and Class A, and security upgrades for scan of documents for viruses.

<u>Capital Contributions Variance ($2,471K)</u>

Capital contributions recorded in 2017 include: ($723K) for new subdivisions and ($902K) for expansion facilities transferred from customers.

Table 2.1.2.6 – 2018 Actual vs. 2017 Actual

UsoA	Description	2017 Actual	2018 Actual	Variance $
	Land & Buildings			
1805	Land	507,273	507,273	-
1808	Buildings	111,638	111,638	-
1905	Land	508,970	508,970	-
1908	Buildings	17,654,923	18,679,787	1,024,864
1910	Leasehold Improvements	120,252	120,252	-
	Sub-total	18,903,056	19,927,920	1,024,864
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	6,709,755	6,845,044	135,288
1820	Distribution Station Equipment	7,105,405	6,969,921	(135,484)
	Sub-total	13,815,161	13,814,965	(196)
	Poles & Wires			
1830	Poles, Towers & Fixtures	52,203,372	54,187,733	1,984,361
1835	Overhead Conductors & Devices	36,694,266	39,044,434	2,350,169
1840	Underground Conduit	13,214,100	14,270,567	1,056,468
1845	Underground Conductors & Devices	80,230,387	82,442,652	2,212,265
	Sub-total	182,342,124	189,945,387	7,603,262
	Line Transformers			
1850	Line Transformers	43,637,990	45,434,847	1,796,857
	Sub-total	43,637,990	45,434,847	1,796,857
	Services & Meters			
1855	Services	9,793,963	11,110,941	1,316,978
1860	Meters	11,125,932	12,029,941	904,008
	Sub-total	20,919,895	23,140,881	2,220,986
	IT Assets			
1920	Computer Equipment Hardware	4,879,232	5,202,743	323,511
	Sub-total	4,879,232	5,202,743	323,511
	Equipment			
1915	Office Furniture & Equipment	1,741,871	1,856,959	115,088
1930	Transportation Equipment	9,666,390	9,762,133	95,744
1935	Stores Equipment	323,279	328,495	5,215
1940	Tools, Shop & Garage Equipment	2,289,678	2,355,710	66,032
1945	Measurement & Testing Equipment	204,006	204,006	-
1955	Communications Equipment	1,360,855	1,470,680	109,826
1960	Miscellaneous Equipment	72,951	72,951	-
1980	System supervisor Equipment	128,961	128,961	-
	Sub-total	15,787,990	16,179,895	391,904
	Intangible Assets			
1611	Computer Software	4,465,687	4,754,578	288,891
1612	Land Rights	1,604,397	1,604,397	-
	Sub-total	6,070,084	6,358,975	288,891
	Total - Gross Assets	**306,355,532**	**320,005,612**	**13,650,080**
	Capital Contributions			
2440	Deferred Revenue	(34,557,685)	(37,095,719)	(2,538,034)
	Sub-total	(34,557,685)	(37,095,719)	(2,538,034)
	Total - Gross Assets Net of Capital Contributions	**271,797,847**	**282,909,893**	**11,112,046**

Land and Buildings Variance $1,025K

Building expenditures in 2018 include the costs related to the schematic drawings and design of a new garage and truck washing facility, and the purchase of the hoists for the new garage and other mechanical equipment.

The existing vehicle service garage was designed and constructed within the operations centre at 7447 Pin Oak Drive in 1984 (35 years ago) and was sized and outfitted with equipment that accommodated the requirements of the company fleet complement of the day. Future considerations of the physical size of vehicles and the number of fleet equipment were incorporated into the design at that time, but those capacities and numbers have been exceeded for some years now. On average, the size and weight of the large service vehicles has increased by 30 to 40 percent and the number of vehicles in the fleet has doubled since the garage was designed and built. The garage is now too small to provide for the needed space to service the number of vehicles we have, and the limited capacities of the vehicle hoisting systems have been reached and they are near the end of their useful life. To maintain safe and efficient servicing for our fleet of equipment a new facility is required.

The new Service Garage facility will provide space to accommodate up to, two large and two small vehicles at one time (twice the existing capacity). The hoisting systems will have greater lifting capacities and will incorporate the latest safety technologies. Environmental management features will be incorporated where required and energy efficient systems will be installed to be environmentally responsible and respectful. Construction of the new facility will commence in 2019 and completion is expected in the second quarter of 2020. The new service facility will provide a modern, safe, efficient and environmentally friendly environment to service our complement of vehicles and will support our equipment servicing requirements for decades to come.

Included in the new service garage facility building footprint will be a roughed in truck washing bay. Currently all vehicle washing is performed in the large vehicle parking garage. Washing vehicles in this area results in a perpetually wet environment that creates slipping hazards and accelerates the degradation of the concrete floor. It is anticipated the truck washing facilities will be installed in the future. The cost of the building includes the base building, site servicing, mechanical, electrical, and engineering fees.

<u>Poles and Wires Variance $7,603K</u>
<u>Line Transformers Variance $1,797K</u>
<u>Services and Meters Variance $2,221K</u>
Significant components of NPEI's distribution system investments in 2018 include: Customer Driven System Reinforcements and New Commercial Connections $2,533K, Subdivisions $1,020K, Overhead Rebuilds $3,583K, Pole Replacements $882K, Kiosk Replacements $123K, Switchgear Replacements $164K, Sustainment $931K and Transfer of Expansion Facilities from Customers $914K.

During 2018, NPEI replaced 200 conventional meters with MIST meters.

NPEI has completed the OEB's Appendix 2-AA, which provides further details of individual project and capital program costs by year, and is included as Appendix 2-4 to this Exhibit. Descriptions of individual projects and programs for 2015-2020 are provided in Exhibit 2.2.2.

<u>IT Assets Variance $324K</u>
Computer Hardware expenditures for 2018 include: 2 new nodes for hyper-convergence virtual environment conversion, a new colour bill printer, computers, laptops, tablets new IVR hardware for the phone answering system, and equipment for Airwatch, which is a device used for cell phone cyber security protection.

<u>Equipment Variance $392K</u>
Equipment expenditures for 2018 include:

- Replacement of 3 pick-up trucks for a total of $121K.
- The chassis for a new radial boom derrick truck for $150K.
- An underground cable pulling machine for $198K.
- Vehicle disposals in 2018 are ($424K).

Intangible Assets Variance $289K

Computer Software additions for 2018 include: CIS updates for contact management, m-care, sequel server reporting services, In-Service dispatcher and I-net viewer licences as well as other GIS configuration updates, and the purchase of Quadra, which is software used for engineering design and estimating.

Capital Contributions Variance ($2,538K)

Capital contributions recorded in 2018 include: ($770K) for new subdivisions and ($914K) for expansion facilities transferred from customers.

Table 2.1.2.7 – 2019 Actual vs. 2018 Actual

UsoA	Description	2018 Actual	2019 Actual	Variance $
	Land & Buildings			
1805	Land	507,273	507,273	-
1808	Buildings	111,638	111,638	-
1905	Land	508,970	508,970	-
1908	Buildings	18,679,787	20,717,683	2,037,896
1910	Leasehold Improvements	120,252	120,252	-
	Sub-total	19,927,920	21,965,816	2,037,896
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	6,845,044	7,044,289	199,245
1820	Distribution Station Equipment	6,969,921	7,119,637	149,716
	Sub-total	13,814,965	14,163,926	348,961
	Poles & Wires			
1830	Poles, Towers & Fixtures	54,187,733	55,827,640	1,639,906
1835	Overhead Conductors & Devices	39,044,434	40,965,809	1,921,374
1840	Underground Conduit	14,270,567	14,778,417	507,850
1845	Underground Conductors & Devices	82,442,652	85,815,272	3,372,620
	Sub-total	189,945,387	197,387,137	7,441,750
	Line Transformers			
1850	Line Transformers	45,434,847	47,947,933	2,513,086
	Sub-total	45,434,847	47,947,933	2,513,086
	Services & Meters			
1855	Services	11,110,941	12,779,084	1,668,143
1860	Meters	12,029,941	12,776,483	746,543
	Sub-total	23,140,881	25,555,567	2,414,686
	IT Assets			
1920	Computer Equipment Hardware	5,202,743	5,395,892	193,149
	Sub-total	5,202,743	5,395,892	193,149
	Equipment			
1915	Office Furniture & Equipment	1,856,959	1,941,662	84,704
1930	Transportation Equipment	9,762,133	10,321,378	559,245
1935	Stores Equipment	328,495	328,495	-
1940	Tools, Shop & Garage Equipment	2,355,710	2,447,550	91,841
1945	Measurement & Testing Equipment	204,006	204,006	-
1955	Communications Equipment	1,470,680	1,593,239	122,559
1960	Miscellaneous Equipment	72,951	72,951	-
1980	System supervisor Equipment	128,961	128,961	-
	Sub-total	16,179,895	17,038,242	858,348
	Intangible Assets			
1611	Computer Software	4,754,578	5,116,351	361,773
1612	Land Rights	1,604,397	1,604,397	-
	Sub-total	6,358,975	6,720,747	361,773
	Total - Gross Assets	**320,005,612**	**336,175,261**	**16,169,649**
	Capital Contributions			
2440	Deferred Revenue	(37,095,719)	(42,558,399)	(5,462,680)
	Sub-total	(37,095,719)	(42,558,399)	(5,462,680)
	Total - Gross Assets Net of Capital Contributions	**282,909,893**	**293,616,862**	**10,706,969**

<u>Land and Buildings Variance $2,038K</u>

Building expenditures in 2019 include the first phase of construction of NPEI's new garage and truck washing facility.

<u>Poles and Wires Variance $7,442K</u>

<u>Line Transformers Variance $2,513K</u>

<u>Services and Meters Variance $2,415K</u>

Significant components of NPEI's distribution system investments in 2019 include: Customer Driven System Reinforcements and New Commercial Connections $2,543K, Subdivisions $1,984K, Overhead Rebuilds $1,954K, Pole Replacements $963K, Switchgear Replacements $309K, Sustainment $1,274K, and Transfer of Expansion Facilities from Customers $2,312K.

During 2019, NPEI energized 18 subdivisions of various sizes. This represents an increase in subdivision development over the previous several years (2018 = 8 subdivisions energized; 2017 = 9; 2016 = 7; 2015 = 12). This is reflected in an increase of $965K in subdivisions costs in 2019 versus 2018, as well as an increase of $1,312K in the value of expansion facilities transferred from customers in 2019 versus 2018.

NPEI's 2015 COS Rate Application (EB-2014-0096) included an estimate of 915 conventional meters to be replaced between 2015 and 2020. During the past 5 years, these accounts were reviewed for customer demand. The revised total number of meters to be replaced with MIST meters is 675, of which 410 were replaced during 2016-2018, with the remaining 265 replaced in 2019. The remaining 240 meters were determined to be replaced with smart meters, which will be completed during 2020.

NPEI has completed the OEB's Appendix 2-AA, which provides further details of individual project and capital program costs by year, and is included as Appendix 2-4 to this Exhibit. Descriptions of individual projects and programs for 2015-2020 are provided in Exhibit 2.2.2.

IT Assets Variance $193K

Computer Hardware expenditures for 2019 largely include the replacement of 6 servers which reached end of life.

Equipment Variance $858K

Equipment expenditures for 2019 include:

- Replacement of 1 pick-up truck for $40K
- A mini track machine for $248K
- The body for a new radial boom derrick for $264K. The chassis was constructed in 2018.
- Snowplow and 2 new trailers for a total of $48K.
- Vehicle disposals in 2019 are ($40K).

Intangible Assets Variance $362K

Computer Software additions for 2019 include: CIS updates for contact management and File Nexus document storage. NPEI implemented Quadra and Job Cost in 2019. Quadra is a software program used for design and estimating which interfaces with Job Cost, a third-party module in Great Plains. In the GIS system, NPEI installed Networks Professional, which allows for the upgrade to a browser-based iNet Viewer versus the purchase of individual licenses.

Capital Contributions Variance ($5,463K)

Capital contributions recorded in 2019 include: ($2,456K) for new subdivisions and ($2,312K) for expansion facilities transferred from customers.

As indicated above, a larger number of subdivisions were completed during 2019 compared to previous years, which resulted in an increase over 2018 in both the level of capital contributions billed to developers to recover costs incurred by NPEI, as well as the amount of expansion facilities transferred from customers, as follows:

Capital Contributions	2019	2018	Variance
Expansion Facilities Transferred from Customers	2,312,132	913,711	1,398,421
Subdivision Capital Contributions	2,456,241	769,927	1,686,315
Other Capital Contributions	694,307	854,396	(160,090)
Total	**5,462,680**	**2,538,034**	**2,924,645**

1 **Table 2.1.2.8 – 2020 Bridge vs. 2019 Actual**

UsoA	Description	2019 Actual	2020 Bridge	Variance $
	Land & Buildings			
1805	Land	507,273	507,273	-
1808	Buildings	111,638	111,638	-
1905	Land	508,970	508,970	-
1908	Buildings	20,717,683	22,485,783	1,768,100
1910	Leasehold Improvements	120,252	120,252	-
	Sub-total	21,965,816	23,733,916	1,768,100
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	7,044,289	7,119,289	75,000
1820	Distribution Station Equipment	7,119,637	7,119,637	-
	Sub-total	14,163,926	14,238,926	75,000
	Poles & Wires			
1830	Poles, Towers & Fixtures	55,827,640	58,101,314	2,273,675
1835	Overhead Conductors & Devices	40,965,809	43,039,853	2,074,044
1840	Underground Conduit	14,778,417	17,238,359	2,459,942
1845	Underground Conductors & Devices	85,815,272	90,259,889	4,444,617
	Sub-total	197,387,137	208,639,416	11,252,278
	Line Transformers			
1850	Line Transformers	47,947,933	49,123,794	1,175,861
	Sub-total	47,947,933	49,123,794	1,175,861
	Services & Meters			
1855	Services	12,779,084	14,097,983	1,318,899
1860	Meters	12,776,483	13,535,443	758,960
	Sub-total	25,555,567	27,633,426	2,077,859
	IT Assets			
1920	Computer Equipment Hardware	5,395,892	5,565,992	170,100
	Sub-total	5,395,892	5,565,992	170,100
	Equipment			
1915	Office Furniture & Equipment	1,941,662	2,035,962	94,300
1930	Transportation Equipment	10,321,378	10,484,525	163,147
1935	Stores Equipment	328,495	328,495	-
1940	Tools, Shop & Garage Equipment	2,447,550	2,512,250	64,700
1945	Measurement & Testing Equipment	204,006	204,006	-
1955	Communications Equipment	1,593,239	1,693,239	100,000
1960	Miscellaneous Equipment	72,951	72,951	-
1980	System supervisor Equipment	128,961	128,961	-
	Sub-total	17,038,242	17,460,389	422,147
	Intangible Assets			
1611	Computer Software	5,116,351	5,457,351	341,000
1612	Land Rights	1,604,397	1,604,397	-
	Sub-total	6,720,747	7,061,747	341,000
	Total - Gross Assets	**336,175,261**	**353,457,606**	**17,282,345**
	Capital Contributions			
2440	Deferred Revenue	(42,558,399)	(46,412,572)	(3,854,173)
	Sub-total	(42,558,399)	(46,412,572)	(3,854,173)
	Total - Gross Assets Net of Capital Contributions	**293,616,862**	**307,045,034**	**13,428,172**

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Land and Buildings Variance $1,768K

Building expenditures in 2020 include the completion of NPEI's new garage and truck washing facility.

Poles and Wires Variance $11,252K

Line Transformers Variance $1,176K

Services and Meters Variance $2,078K

Significant components of NPEI's distribution system investments in 2020 include: Customer Driven System Reinforcements and New Commercial Connections $4,105K, Municipal Road Relocations $2,277K, Subdivisions $902K, Overhead Rebuilds $2,806K, Pole Replacements $701K, Kiosk Replacements $53K, Switchgear Replacements $86K, Sustainment $873K and Transfer of Expansion Facilities from Customers $1,000K.

Overall, the system access budget of $9.5M before capital contributions accounts for 64% of NPEI's 2020 capital project budget. On a net basis after capital contributions, system access projects account for 52% of the 2020 capital project budget. The other main driver of the increased system access customer driven projects in 2020 is the Canada Summer games coming to the Niagara Region is 2021. Prior to the announcement regarding the new South Niagara hospital, NPEI's 2020 budget was 53% system renewal and 39% system access. The Canada Summer games being held in the Niagara Region in 2021 and the new hospital are the main drivers for the increase in capital spending in 2020. Approximately, $1.6M of system renewal projects were deferred to future years in order to accommodate the increase in system access projects.

NPEI has completed the OEB's Appendix 2-AA, which provides further details of individual project and capital program costs by year, and is included as Appendix 2-4 to this Exhibit. Descriptions of individual projects and programs for 2015-2020 are provided in Exhibit 2.2.2.

IT Assets Variance $170K

Computer Hardware expenditures for 2020 largely include the Replacement of network switches, physical servers, telephones, PC's, monitors and tablets/laptops which are at end of life.

Equipment Variance $422K

Equipment expenditures for 2020 include:

- Replacement of 1 metering van (from 2007) for $40K
- Purchase of the chassis only for the replacement of a 2003 bucket truck for $150K. The body will be purchased in 2021.

Intangible Assets Variance $341K

Computer Software additions for 2020 include: upgrades for Hexagon GIS, Northstar CIS, Great Plains, interactive forms and website.

Capital Contributions Variance ($3,854K)

Capital contributions for the 2020 Bridge year include: ($1,000K) for expansion facilities transferred from customers, and ($2,636K) for customer driven system access work, including subdivisions.

1 **Table 2.1.2.9 – 2021 Test vs. 2020 Bridge**

UsoA	Description	2020 Bridge	2021 Test	Variance $
	Land & Buildings			
1805	Land	507,273	507,273	-
1808	Buildings	111,638	111,638	-
1905	Land	508,970	508,970	-
1908	Buildings	22,485,783	22,721,283	235,500
1910	Leasehold Improvements	120,252	120,252	-
	Sub-total	23,733,916	23,969,416	235,500
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	7,119,289	8,818,886	1,699,597
1820	Distribution Station Equipment	7,119,637	7,119,637	-
	Sub-total	14,238,926	15,938,523	1,699,597
	Poles & Wires			
1830	Poles, Towers & Fixtures	58,101,314	61,437,851	3,336,537
1835	Overhead Conductors & Devices	43,039,853	45,085,446	2,045,593
1840	Underground Conduit	17,238,359	19,542,266	2,303,907
1845	Underground Conductors & Devices	90,259,889	93,361,252	3,101,363
	Sub-total	208,639,416	219,426,816	10,787,400
	Line Transformers			
1850	Line Transformers	49,123,794	50,680,361	1,556,567
	Sub-total	49,123,794	50,680,361	1,556,567
	Services & Meters			
1855	Services	14,097,983	15,534,443	1,436,461
1860	Meters	13,535,443	14,067,093	531,650
	Sub-total	27,633,426	29,601,537	1,968,111
	IT Assets			
1920	Computer Equipment Hardware	5,565,992	5,904,772	338,780
	Sub-total	5,565,992	5,904,772	338,780
	Equipment			
1915	Office Furniture & Equipment	2,035,962	2,115,062	79,100
1930	Transportation Equipment	10,484,525	10,720,468	235,943
1935	Stores Equipment	328,495	328,495	-
1940	Tools, Shop & Garage Equipment	2,512,250	2,589,550	77,300
1945	Measurement & Testing Equipment	204,006	204,006	-
1955	Communications Equipment	1,693,239	1,818,239	125,000
1960	Miscellaneous Equipment	72,951	72,951	-
1980	System supervisor Equipment	128,961	128,961	-
	Sub-total	17,460,389	17,977,732	517,343
	Intangible Assets			
1611	Computer Software	5,457,351	5,731,651	274,300
1612	Land Rights	1,604,397	1,604,397	-
	Sub-total	7,061,747	7,336,047	274,300
	Total - Gross Assets	**353,457,606**	**370,835,204**	**17,377,598**
	Capital Contributions			
2440	Deferred Revenue	(46,412,572)	(48,995,800)	(2,583,228)
	Sub-total	(46,412,572)	(48,995,800)	(2,583,228)
	Total - Gross Assets Net of Capital Contributions	**307,045,034**	**321,839,404**	**14,794,371**

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<u>Land and Buildings Variance $236K</u>

Proposed building expenditures included in the 2021 Test Year of $245K are based on the average of NPEI's estimated annual building expenditures for the 5-year period of 2021 – 2025.

Table 2.1.2.10 – 2021 Test Year Building Additions

Building	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Replace 2 Rooftop Heat/AC Units	24,000			25,000	25,000	74,000	14,800
Quansa Hut for Salt	25,000					25,000	5,000
LED Lights for Parking Lot	10,000					10,000	2,000
Contractor Storage Drummond MS - Fence	8,000					8,000	1,600
Concrete Repair NF Garage	400,000					400,000	80,000
Asphalting of SV Yard		400,000				400,000	80,000
Kalar TS Remaining Wall Repairs			275,000			275,000	55,000
Renovate Mechanics Bay into Metershop	25,000					25,000	5,000
Repaint Exterior NPEI (115m of steel barrier on roof plus Stores Window)		10,000				10,000	2,000
Total Building	**492,000**	**410,000**	**275,000**	**25,000**	**25,000**	**1,227,000**	**245,400**

<u>Poles and Wires Variance $10,787K</u>

<u>Line Transformers Variance $1,557K</u>

<u>Services and Meters Variance $1,968K</u>

Significant components of NPEI's proposed distribution system investments in 2021 include: Customer Driven System Reinforcements and New Commercial Connections $2,301K, Subdivisions $916K, Municipal Road Relocations $541K, Overhead Rebuilds $3,737K, Pole Replacements $657K, Kiosk Replacements $646K, Switchgear Replacements $381K, Sustainment $878K and Transfer of Expansion Facilities from Customers $1,000K.

NPEI has completed the OEB's Appendix 2-AA, which provides further details of individual project and capital program costs by year, and is included as Appendix 2-4 to this Exhibit. Descriptions of individual projects and programs for 2021 are provided in Appendix A of NPEI's Distribution System Plan.

<u>IT Assets Variance $339K</u>

Proposed computer equipment expenditures included in the 2021 Test Year of $339K are based on the average of NPEI's estimated annual hardware expenditures for the 5-year period of 2021 – 2025 of $333K, plus average cell phone expenditures of $6K.

Table 2.1.2.11 – 2021 Test Year Hardware Additions

Hardware	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Network Switches	36,000	54,000	54,000	36,000	-	180,000	36,000
Backup Strategy	-	-	10,000	-	-	10,000	2,000
Physical Servers	68,000	-	-	30,000	44,000	142,000	28,400
VX Rail Servers-Virtual Environment	90,000	310,000	220,000	110,000	-	730,000	146,000
Printers	-	700	5,000	-	-	5,700	1,140
Phones	2,000	2,000	2,000	2,000	2,000	10,000	2,000
PC/Monitor	24,000	24,000	24,000	24,000	24,000	120,000	24,000
Equipment	3,600	3,600	33,600	46,200	3,600	90,600	18,120
Cyber Security	-	-	53,600	92,600	92,600	238,800	47,760
Tablets/Laptops	31,200	26,400	26,400	26,400	26,400	136,800	27,360
Total Hardware	**254,800**	**420,700**	**428,600**	**367,200**	**192,600**	**1,663,900**	**332,780**

Cell Phones	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Total Cell Phones	**6,000**	**6,000**	**6,000**	**6,000**	**6,000**	**30,000**	**6,000**

<u>Equipment Variance $517K</u>

Proposed equipment expenditures included in the 2021 Test Year are based on the average of NPEI's estimated annual expenditures for the 5-year period of 2021 – 2025, as follows:

Table 2.1.2.12 – 2021 Test Year Office Furniture & Equipment Additions

Office Equipment	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Ergonomic Office Equipment	10,000	10,000	10,000	10,000	10,000	50,000	10,000
2 Mobile Radio replacements	4,500	4,500	4,500	4,500	4,500	22,500	4,500
General Equipment as needed	10,000	10,000	10,000	10,000	10,000	50,000	10,000
Photcopier	26,000	26,000	-	26,000	26,000	104,000	20,800
Engineering Plotter	20,000					20,000	4,000
Security cameras	30,000		35,000			65,000	13,000
Defibrilator	8,800	8,800	8,800	8,800	8,800	44,000	8,800
Mail machine	10,000			30,000		40,000	8,000
Total Office Equipment	**119,300**	**59,300**	**68,300**	**89,300**	**59,300**	**395,500**	**79,100**

Table 2.1.2.13 – 2021 Test Year Vehicles < 3 Tonnes Additions

Vehicles < 3 tonnes	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Pickup truck #39 (2013)	40,000					40,000	8,000
Engineering Vehicle #49 (2007)	40,000					40,000	8,000
Pickup truck #38 (2013)		40,000				40,000	8,000
Pickup truck #37 (2013)		40,000				40,000	8,000
Pickup truck #17 (2015)			40,000			40,000	8,000
Pickup truck #51 (2009)			40,000			40,000	8,000
Pickup truck #18 (2015)				40,000		40,000	8,000
Pickup truck #19 (2015)				40,000		40,000	8,000
Pickup truck #3 (2013)				40,000		40,000	8,000
Pickup truck #23 (2013)					40,000	40,000	8,000
Pickup truck #35 (2015)					40,000	40,000	8,000
Pickup truck #31 (2015)					40,000	40,000	8,000
Total Vehicle < 3 tonnes	**80,000**	**80,000**	**80,000**	**120,000**	**120,000**	**480,000**	**96,000**

Table 2.1.2.14 – 2021 Test Year Vehicles > 3 Tonnes Additions

Vehicles > 3 tonnes	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Bucket Truck TR 42 (2003)	270,000					270,000	54,000
Digger Derrick #16 (2005)	150,000	270,000				420,000	84,000
Freightliner TR#50 (2008)		150,000	270,000			420,000	84,000
Freightliner TR#58 (2009)			150,000	270,000		420,000	84,000
Digger Derrick #60 (2010)				150,000	270,000	420,000	84,000
Total Vehicle > 3 tonnes	**420,000**	**420,000**	**420,000**	**420,000**	**270,000**	**1,950,000**	**390,000**

Table 2.1.2.15 – 2021 Test Year Other Transportation Equipment Additions

Other Transportation Equipment	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Reel trailer				20,000	20,000	40,000	8,000
Bob Cat Snowblower Attachment	10,000					10,000	2,000
Tension machine		135,000				135,000	27,000
Automated traffic flagger			45,000			45,000	9,000
Two Pole Trailers with load tie requirements	40,000					40,000	8,000
Wood Chipper and Trailer		30,000				30,000	6,000
Total Other Transportation Equipment	**50,000**	**165,000**	**45,000**	**20,000**	**20,000**	**300,000**	**60,000**

Table 2.1.2.16 – 2021 Test Year Tools, Shop & Garage Equipment Additions

Tools	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
New tools for new budgeted trucks	15,000	15,000	15,000	15,000	15,000	75,000	15,000
Miscellaneous Replacement Tools	12,000	12,000	12,000	12,000	12,000	60,000	12,000
Grounding Mats					20,000	20,000	4,000
Battery Tools	8,000	8,000	8,000	8,000	8,000	40,000	8,000
Stringing Blocks	1,200	1,200	1,200	1,200	1,200	6,000	1,200
Diagnostic Equipment	5,000	5,000	5,000	5,000	5,000	25,000	5,000
Concrete Saws, Generators, Water Pumps, Chainsaws	5,000	5,000	5,000	5,000	5,000	25,000	5,000
Total tools for garage	11,000	11,000	11,000	11,000	11,000	55,000	11,000
Spider Rope System		17,000				17,000	3,400
Travellers - For 1000MCM and annual replacement	-	2,000	2,000	2,000	2,000	8,000	1,600
Trimble Replacement Geo 7X			-	17,000		17,000	3,400
2 Sets of O/H Digital Recording Ammeters			25,000			25,000	5,000
Fault Finder	6,000					6,000	1,200
Primary Metering - Hotstick ammeter & stick	-	2,500	-	2,500	2,500	7,500	1,500
Total Tools	**63,200**	**78,700**	**84,200**	**78,700**	**81,700**	**386,500**	**77,300**

<u>Intangible Assets Variance $274K</u>

Proposed computer software expenditures included in the 2021 Test Year of $274K are based on the average of NPEI's estimated annual software expenditures for the 5-year period of 2021 – 2025.

Table 2.1.2.17 – 2021 Test Year Software Additions

Software	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Hexagon	135,000	120,000	50,000	-	-	305,000	61,000
Hexagon Sustainable Engineering hours	15,000	15,000	15,000	15,000	15,000	75,000	15,000
Dess data	-	-	-	30,000	-	30,000	6,000
Radio GPS system upgrade	-	15,000	-	15,000	-	30,000	6,000
Forms-Silverblaze	10,000	10,000	10,000	10,000	10,000	50,000	10,000
Great Plains	-	20,000	-	50,000	-	70,000	14,000
Barcoding	-	45,000	-	-	-	45,000	9,000
Northstar	65,000	65,000	90,000	90,000	65,000	375,000	75,000
Office 2016	-	39,000	-	-	39,000	78,000	15,600
File Nexus	-	30,000	-	30,000	-	60,000	12,000
Intranet	-	-	1,500	-	-	1,500	300
Mitel upgrade & Software Assurance	35,000	-	-	-	-	35,000	7,000
Rugged.com upgrade	75,000	-	-	-	-	75,000	15,000
Data Domain software (5 years)	-	44,000	-	-	-	44,000	8,800
Data Domain / Networker software (5 years)	-	98,000	-	-	-	98,000	19,600
Total Software	**335,000**	**501,000**	**166,500**	**240,000**	**129,000**	**1,371,500**	**274,300**

Capital Contributions Variance ($2,583K)

Capital contributions for the 2021 Test Year include: ($1,000K) for expansion facilities transferred from customers and ($1,200K) for customer driven system access work, and ($168K) for road relocations.

ACCUMULATED DEPRECIATION

2.1.3 Accumulated Depreciation

NPEI confirms that the additions to accumulated depreciation in the OEB's Appendix 2-BA Fixed Asset Continuity Schedules (Appendix 2-1 to this Exhibit) agree to the depreciation expense reported in Exhibit 4 for each year 2015 to 2021.

NPEI confirms that disposals have been included, for both cost and accumulated depreciation, in the OEB's Appendix 2-BA.

ALLOWANCE FOR WORKING CAPITAL

2.1.4 Allowance for Working Capital

Section 2.2.1.3 of the Filing Requirements states:

"In a letter dated June 3, 2015, the OEB provided an update to the OEB's policy for the calculation of the allowance for working capital. The applicant may take one of two approaches for the calculation of its allowance for working capital: (1) use the default allowance of 7.5% of the sum of Cost of Power (CoP) and OM&A or (2) file a lead/lag study.

If the applicant has been directed by the OEB to undertake a lead/lag study as part of its last rate application, it must comply with that order."

In NPEI's 2015 COS Rate Application (EB-2015-0094), the OEB approved NPEI's 2015 distribution rates on an interim basis, based on a placeholder Working Capital Allowance ("WCA") percentage of 13%. The Board ordered NPEI to complete a lead-lag study to be filed with NPEI's 2016 IRM Rate Application. In NPEI's 2016 IRM Rate Application (EB-2015-0090), the Board found that NPEI's final 2015 Revenue Requirement should be based on a WCA percentage of 10.48%.

In this current application, NPEI has utilized the default WCA percentage of 7.5%.

Exhibit 2: Rate Base

Tab 2 (of 3): Capital Expenditures

PLANNING

2.2.1 Planning

NPEI has prepared a Distribution System Plan ("DSP") in accordance with the OEB's *Chapter 5 Consolidated Distribution System Plan Filing Requirements* ("Chapter 5 Filing Requirements), dated July 12, 2018, in support of the proposals included in this Application.

NPEI engaged Kinetrics Inc. ("Kinetrics") to update its Asset Condition Assessment ("ACA"). The ACA Report prepared by Kinetrics is included as Appendix E to the DSP.

NPEI's DSP has been prepared to support the four key objectives of the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* ("RRFE"):

1) Customer Focus: services are provided in a manner that responds to identified customer preferences;
2) Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
3) Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4) Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

The DSP contains five sections corresponding to the sections of the Chapter 5 Filing Requirements:

1) Introduction
2) General and Administrative Matters

3) Distribution System Plans
4) Asset Management Process.
5) Capital Expenditure Plan

In preparation for filling its Cost of Service Application and in keeping with the requirements of the RRFE, NPEI engaged Innovative Research Group to support enhanced customer engagement outreach to assess customer needs, wants, and preferences with respect to NPEI's Distribution System and Business Plan. NPEI and Innovative developed a workbook that explains the content of NPEI's proposed plan, the cost pressures that drive NPEI's decision making process, and the choices customers have that can help inform NPEI's plans.

Responding to Customer Preferences

Overall, NPEI's customers were supportive of its 2021-2025 draft plan as it was presented during the customer engagement process. In each of the three workbooks (Residential, Small Business and GS > 50 kW), the majority of customers surveyed indicated a preference for NPEI to either maintain the proposed rate increase to deliver a program that focuses on the priorities of its draft plan, or to improve service even if that means an increase that exceeds what is proposed in the draft plan.

In each case however, the customer support for maintaining the proposed level of rate increase was greater than the customer support for improving service even if that means an increase that exceeds what is proposed in the draft plan.

Further, among Vulnerable Residential customers, a minority (29%) indicated that NPEI should keep increases below what is proposed in the draft plan even if that means reductions in service, compared to 11% of Residential customers overall.

In determining whether to adjust the overall level of spending proposed in its draft plan, NPEI has considered the following factors:

- Balancing customer preferences in general against the preferences expressed by the more vulnerable Residential customers.
- The resulting level of bill impacts to all customer classes.
- Internal resource constraints: whether or not an increase in the overall level of proposed capital projects or programs may require additional engineering or operations resources beyond NPEI's current staffing levels.
- Financial leverage: whether or not an increase in the overall level of proposed capital projects or programs may require NPEI to incur additional debt.

Based on the above considerations, NPEI has decided to maintain the overall proposed level of capital spending consistent with what was included in the draft plan.

In response to customer preferences on pacing of capital investments, NPEI has made adjustments to several specific capital programs, as detailed below.

In addition, if capital projects or programs that are planned during the 2021-2025 period need to be deferred, NPEI will incorporate customer preferences when selecting alternative projects to prioritize.

Overhead Pole Replacement

Among Residential customers, a plurality (47%) indicated a preference for an accelerated pace, while among Vulnerable Residential customers, a plurality (43%) indicated a preference for a slower pace than what was proposed in the draft plan.
Among Small Business Customers, a majority (56%) indicated a preference for an accelerated pace.

Of the GS>50 kW respondents, 15 of 32 indicated a preference for the pace that was included in the draft plan.

In considering the overall customer preferences from each rate class, as well as the specific preferences of the more vulnerable Residential customers, NPEI has not adjusted its proposed plan for Overhead Pole Replacement.

Overhead Transformer Replacement

Among Residential customers, a plurality (47%) indicated a preference for an accelerated pace, while among Vulnerable Residential customers, a plurality (38%) indicated a preference for a slower pace than what was proposed in the draft plan.
Among Small Business Customers, a majority (53%) indicated a preference for an accelerated pace.

Of the GS>50 kW respondents, 14 of 32 indicated a preference for an accelerated pace and 12 of 32 indicated a preference for what was included in the draft plan.

Although there is an apparent overall preference for an accelerated pace, Vulnerable Residential customers prefer a slower pace. In addition, the majority of Residential and GS>50 kW customers preferred either the draft plan or slower pace.
Therefore, NPEI has not adjusted its proposed plan for Overhead Transformer Replacement.

Converting Outdated Underground Kiosk Transformers

Among Residential customers, a majority (56%) indicated a preference for the pace that was included in the draft plan, while among Vulnerable Residential customers, a strong majority (73%) indicated a preference for either a reduced pace, or an even slower pace.
Among Small Business Customers, a majority (60%) indicated a preference for the pace that was included in the draft plan.

Of the GS>50 kW respondents, 21 of 32 indicated a preference for the pace that was included in the draft plan.

Although there is an apparent overall preference for the pace that was included in the draft plan, 73% of Vulnerable Residential exhibited a preference for a reduced pace or an even slower pace. In response, NPEI has reduced the proposed Conversion of

Outdated Underground Kiosk Transformers Program from replacing 11 units per year to 8 units per year, resulting in a reduction of $242,000 to this program.

Underground Cable Replacement

Among Residential customers, a majority (65%) indicated a preference for an accelerated pace, or an even further accelerated pace, while among Vulnerable Residential customers, a majority (58%) indicated a preference for an accelerated pace, or an even further accelerated pace.

Among Small Business Customers, a majority (68%) indicated a preference for an accelerated pace, or an even further accelerated pace.

Of the GS>50 kW respondents, 16 of 32 indicated a preference for the pace that was included in the draft plan, 14 of 32 indicated a preference for an accelerated pace and 2 of 32 preferred a further accelerated pace.

In response to the overall preference amongst all customer types for an accelerated pace or an even further accelerated pace, NPEI has increased the level of its Underground Cable Replacement Program. In order to maintain the overall level of proposed capital spending, NPEI has increased the proposed Underground Cable Replacement budget by $242,000, which corresponds to the reduction made to the Conversion of Outdated Underground Kiosk Transformers Program. This proposed increase will allow NPEI to proactively replace approximately 0.3 km of additional underground cable annually.

Subdivision Underground Rehabilitation

Among Residential customers, a plurality (45%) indicated a preference for the pace that was included in the draft plan, while among Vulnerable Residential customers, a plurality (45%) indicated a preference for a slower pace.

Among Small Business Customers, a majority (52%) indicated a preference for the pace that was included in the draft plan.

Of the GS>50 kW respondents, 14 of 32 indicated a preference for a slower pace.
In considering the overall customer preferences from each rate class, as well as the more vulnerable Residential customers, NPEI has not adjusted its proposed plan for Subdivision Underground Rehabilitation.

<u>Overhead Rebuilds</u>

Among Residential customers, a narrow majority (50%) indicated a preference for the pace that was included in the draft plan, while among Vulnerable Residential customers, a plurality (39%) indicated a preference for the pace that was included in the draft plan.
Among Small Business Customers, a plurality (45%) indicated a preference for the pace that was included in the draft plan.

Of the GS>50 kW respondents, 19 of 32 indicated a preference for the pace that was included in the draft plan.

Due to the agreement of overall customer preferences for the pace that was included in the draft plan, NPEI has not adjusted its proposed plan for Overhead Rebuilds.

<u>Grid Modernization</u>

Among Residential customers, a plurality (44%) indicated a preference for the pace that was included in the draft plan, and among Vulnerable Residential customers, a plurality (38%) also indicated a preference for the pace that was included in the draft plan.
Among Small Business Customers, an equal number (41%) indicated a preference for the pace that was included in the draft plan as those who indicated a preference for an accelerated pace.

Of the GS>50 kW respondents, 14 of 32 indicated a preference for the pace that was included in the draft plan and 12 of 32 indicated a preference for an accelerated pace.

Due to the agreement of overall customer preferences for the pace that was included in the draft plan, NPEI has not adjusted its proposed plan for Grid Modernization.

Further details on NPEI's customer engagement activities are provided in Exhibit 1, Tab 7.

NPEI's Distribution System Plan is included as Appendix 2-8 to this Exhibit.

INVESTMENT CATEGORIES

2.2.2 Investment Categories

Table 2.2.2.1 below (Filing Requirements Appendix 2-AA) presents a listing of NPEI's capital projects and programs each year, by investment category.

Table 2.2.2.1 – Capital Projects by Investment Category

Projects	Ref #	2015	2016	2017	2018	2019	2020 Bridge Year	2021 Test Year
System Access								
Customer Driven System Reinforcements for New Commercial Service Connections	1	849,329	736,317	933,983	1,104,336	1,022,512	2,003,964	2,301,448
Commercial Connection Projects Less Than Materiality	2	835,479	1,243,722	1,019,677	1,428,763	1,509,202		
King St. Bell Joint Use Pole Replacement	3	241,068						
NRWC Wind Farm Line Conflicts	4		607,961					
Enercon Wind Farm Line Conflicts	4		430,071					
Eptcon Stringing Conflicts	4		279,261					
FWRN LP Line Conflicts	4		210,545					
Oldfield Rd 3-Ph Pole Line	5		293,937					
Mcleod @ Montrose & Oakwood	6			166,310				
Fallsview Entertainment Complex	7				204,129			
Garner Road Line Rebuild to 3-Phase	8					223,044		
Motor Vehicle Accidents	9	80,382	115,958	258,091	179,628	147,214		
Metering	10	111,450	138,789	601,441	585,648	481,484	397,300	405,050
Warren Woods Subdivision Phase 3	11	172,667						
Oldfield Estates Subdivision Phase 1	11	160,905						
Oldfield Estates Subdivision Phase 2	11		183,381					
Warren Woods Subdivision Phase 4	11		171,972					
Warren Woods Subdivision Phase 4 Stage 2	11			184,983				
Warren Woods Subdivision Phase 5	11				237,427			
Cherry Heights Extension	11					341,970		
Vista Ridge Phase 1	11					237,541		
Warren Woods Phase 5 Stage 2	11					166,032		
Terravita Subdivision	11					148,562		
New Subdivision Projects Below Materiality	11	464,908	476,663	340,921	448,833	660,564		
New Connections in Existing Subdivisions	11	395,224	564,008	577,899	333,345	429,566	901,692	915,516
Transfer of Expansion Facilities from Customers	11	3,160,319	688,452	901,555	913,711	2,312,132	1,000,000	1,000,000
Road Relocation Projects	12	411,612	142,942	93,777	125,864	120,412	54,390	540,923
RMN - Reg Rd #18-Mountain Relocation	12	311,300						
CNF Level St U/G Relocate	12	230,733						
Clifton Hill Primary Upgrade	13		309,573					
KM3 - Link	14					11,092	876,668	
Pin Oak Main Loop	15						1,224,075	
GPI Feeder Build	16						807,178	
Thorold Stone - Bridge Roundabout	17						452,235	
Jordan UG Relocate	18						1,062,995	
RR20 Roundabouts	19						254,825	
Fallsview UG Relocate	20						452,244	
Kalar TS Additional Switchgear	21					110,321		1,699,597
Niagara South Feeders Ph 1								1,603,149
Miscellaneous	22	37,540	(103,819)	622,403	431,220	52,114		
Sub-Total		7,462,916	6,489,732	5,701,039	5,992,903	7,973,762	9,487,566	8,465,683

Projects	Ref #	2015	2016	2017	2018	2019	2020 Bridge Year	2021 Test Year
System Renewal								
Crawford St. Rebuild - Thorold Stone to Sheldon	23	463,166						
Willodel Rd. - Gonder to Koabel	24	313,261						
Willoughby Dr. - Main to Cattell	25	12,799	458,729					
Willoughby Dr. - Cattell to Weinbrenner	26		375,385	318				
Transformer Replacements - PCB > 50 ppm	27	235,322						
Downtown core PILCDSTA Decomissioning	28		382,899	469,444	53,355	75,377		
Station 22 Rebuild - Ph 1 Carryover / Phase 2	29	682,135	202,992					
Beck Road Rebuild - Marshall to Schisler	30	170,696						
Frederica St Rebuild - Dorchester to Drummond	31	14,696	689,884	26,365				
NS&T ROW - Crossing the QEW	32		207,136	159,229				
Jordan Rd Rebuild Phase 2 - Honsberger from Jordan to Thirteenth	33	460,242						
Jordan Rd Rebuild Phase 3	33		307,408					
Jordan Rd Rebuild Phase 4	33			582,371				
Kalar TS Protection Equipment Refurbishment	34			56,943	128,308			
Kalar TS Relay Upgrade	34						75,000	
Dorchester Road Rebuild - McLeod to Dunn	35		377,755	232,048				
Concession 2 Rd - Caistorville Rd to Westbrook Rd	36					157,568		
Thorold Stone Rd Rebuild - Montrose to Kalar	37				10,017	162,768	349,274	
Portage Rd. Rebuild - Mountain to Church's Lane	38				119,863	288,298		
Campden DS Power Tx - Replace with Former Jordan DS Tx	39			35,884				
Station St. DS - Power Transformer Replacement	40			179,626				
Station 14 Voltage Conversion - Phase 1	41			399,195	2,437			
Station 14 Voltge Conversion Phase 2	41				712,832			
Station 14 Voltage Conversion - Phase 3	41					816,054	236,611	
Victoria Ave South of Fly Rd - Phase 1	42		8,936	137,553	694,069			
Victoria Ave South of Fly Rd - Phase 2	42				567,882			
Oakwood Drive - South of Smart Centre to QEW	43			11,808	583,572			
Dorchester Road Rebuild - Mountain to Riall	44		1,943	510,845	204,558			
Chippawa Redundant Supply - Phase 1	45			279,777	67,329			
Chippawa Redundant Supply - River Crossing	45				492,482			
Murray TS - J Bus Metering	46					430,258		
Victoria Ave Rebuild - 7th Ave Phase 2	47					232,172		
Campden DS Tx Failure	48					150,378		
Mountain Road - St. Paul St. to Mewburn	49					297,198		
Sinnicks Ave Rebuild - Thorold Stone to Swayze	50						824,145	
McRae St. Area Rebuild Ph 1	51						351,194	
King St. Rebuild Phase 1 - Bartlett Rd to Sann Rd.	52						344,679	
Cooper - Jill- Jordan - Marie Claude Rebuild								374,856
Prospect - Brittania - Kitchener Voltage Conversion								362,011
King St Rebuild Phase 2 - Sann Rd to Merritt Rd								578,004
Lundy's Lane OH to UG Rebuild - Phase 1								536,750
Sixteen Road Rebuild Regional Rd 14 to McCollum Rd								438,624
Regional Road 14 Sixteen Rd to Twenty Rd								547,178
Cherryhill Rebuild								433,342
McRae St. Area Rebuild Ph 2								466,673
Pole Replacements	53	546,418	583,550	1,009,358	881,938	962,984	700,988	657,323
Kiosk Replacements	54	311,260	1,165,579	937,054	122,613	80,095	52,704	646,096
Switchgear Replacements	55	201,852	222,441	205,352	164,316	308,755	86,218	380,960
Padmount Transformer Replacements								277,762
Polemount Transformer Replacements								410,463
Transformer Collar Replacements								114,635
Pole Mount Step Down Transformer Eliminations - Lincoln / West Lincoln	56						600,106	
Rolling Acres OH to UG Conversion Phase 2	57	764,211						
Rolling Acres OH to UG Conversion Phase 3	57		640,911					
Stanley TS - HONI Initiated	58						625,765	
Subdivision Rehabilitation - Phase 1	59			301,743				
Subdivision Rehabilitation Phase 2	59				450,651	69,938		
Subdivision Rehabilitation Phase 3								603,505
Sub-Total		4,176,057	5,625,547	5,534,913	5,256,221	4,031,843	4,246,684	6,828,182

Projects	Ref #	2015	2016	2017	2018	2019	2020 Bridge Year	2021 Test Year
System Service								
King St. 27.6 kV Extension to Martin Rd	60	130,845						
Heartland Road Extension - Brown Rd to Chippawa Creek	61							
Grid Modernization Program	62	143,148	575,200	(47,512)	161,240	225,929	168,450	209,350
Glenholme to Franklin Ave - 600 MCM UG Install	63		68,207	42,618				
Brown Road Extension - Montrose to Blackburn	64			77,945				
Range Road 2 - East of Allen	65				38,951			
System Sustainment / Minor Betterments	66	1,570,562	1,089,323	1,075,854	931,129	1,274,030	873,020	888,460
Willoughby Road Extension	67				259,547			
Kalar TS Power Transformer Dry Down Equipment	68					72,501		
Greenlane Rd at Ontario - Tie Point	69				1,008		160,278	
Sub-Total		1,844,555	1,732,729	1,148,905	1,391,876	1,572,460	1,201,748	1,097,810
General Plant								
Building		468,660	52,753	403,007	1,024,864	2,037,896	1,768,100	235,500
Hardware		248,789	241,217	332,121	326,559	193,149	170,100	338,780
Software		183,006	342,477	710,896	288,891	361,773	341,000	274,300
Vehicles		490,774	792,445	876,513	518,258	599,766	190,000	546,000
General Equipment		146,974	149,531	116,016	186,335	176,544	159,000	156,400
Sub-Total		1,538,203	1,578,423	2,438,553	2,344,908	3,369,128	2,628,200	1,550,980
Total		**15,021,732**	**15,426,432**	**14,823,410**	**14,985,908**	**16,947,193**	**17,564,198**	**17,942,655**

Further details of all 2015-2020 capital projects and programs that are included in Table 2.2.2.1 are provided below. Further details of NPEI's proposed 2021 capital projects and programs are included in NPEI's Distribution System Plan, which is included as Appendix 2-8 to this Exhibit.

2015-2020 Project Descriptions

Appendix-AA Reference: 1 - 8

Customer Driven System Reinforcements for New Commercial Service Connections

This Capital Program manages an allowance for the construction/upgrade of distribution equipment to facilitate system access connections of new commercial developments. Expansions and reinforcement to the distribution system resulting from these new customer connection requirements fall under this budget allowance.

At the time that NPEI's annual budget is prepared, the specific nature of customer driven projects is not yet known. Therefore, a total amount is included in the annual budget for customer driven costs, and specific jobs are created in NPEI's estimating and accounting systems as NPEI receives customer requests.

In Appendix AA, Reference 1 includes customer driven costs where no capital contribution is required, Reference 2 includes customer driven projects below materiality where a capital contribution is required, and References 3 – 8 are material projects that required a capital contribution.

Material projects include:

- King St. Bell Joint Use Pole Replacement
- Wind Farm line relocations
- Oldfield Road 3-Phase Pole Line
- McLeod @ Montrose and Oakwood
- Fallsview Entertainment Complex
- Garner Road Line Rebuild to 3-Phase

Appendix-AA Reference: 9

Motor Vehicle Accidents

Individual projects are utilized to track cost incurred due to damage to NPEI's distribution system caused by motor vehicle accidents, which are then billed to an insurance company or other third party.

Appendix-AA Reference: 10

Metering

This Capital Program manages an allowance for the metering equipment to facilitate system access connections of new commercial and residential developments. Metering costs resulting from these new customer connection requirements fall under this budget allowance.

In 2014, the Ontario Energy Board provided notice of amendments to the Distribution System Code (the "DSC") pursuant to section 70.2 of the Ontario Energy Board Act, 1998 (the "Act"). The amendments provide notice that a distributor is required to install an interval meter (i.e., a "MIST meter") on any installation this is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW. The Act states these meters are to be changed by August 21, 2020. NPEI's 2015 COS rate application included an estimated 915 meters to be changed between 2015 and 2020. During the past 5 years, the 915 meters were reviewed for customer demand. The total number of MIST meters to be replaced is 675, which were completed by the end of 2019. The remaining 240 conventional meters were determined to be changed to a smart meter which will be completed in 2020.

In the spring of 2017, NPEI received notification from the vendor which provided intermediate communication service for these meters that they would no longer support the metering communication system due to it becoming obsolete in the cellular domain. NPEI identified 225 meters that utilized the 2G network to be replaced in order to avoid possible communication disruptions to these meters that provide energy metering to large commercial customers. NPEI completed 201 of the 2G meter changes in 2017, with the remaining 24 meter changes completed in 2018.

Appendix-AA Reference: 11

New Residential Services (Subdivisions)

This Capital Program manages the installation and connection of new residential services within new and on-going residential developments such as subdivisions.
Individual projects are utilized for each subdivision development. Capital contributions and the transfer of expansion facilities that were constructed under the alternative bid option are completed as per Section 3.2 of the DSC.

Appendix-AA Reference: 12

Line Relocations due to Municipal Road Improvement Requirements

An allowance is maintained for the relocation/construction of distribution facilities to resolve conflicts with planned road works by such Governmental Agencies as the

M.T.O., Regional Municipality of Niagara and the various Municipal Agencies within the Service territory. Additions and reinforcement to the distribution system resulting from new construction requests fall under this budget. Tracking is accomplished with individual Project Numbers assigned to the various projects as required within the Corporate Accounting System.

Capital contributions are collected in accordance with the *Public Service Works on Highways Act.*

Appendix-AA Reference: 13

Clifton Hill Primary Upgrade

Clifton Hill is a famous entertainment destination within the Tourist Core of Niagara Falls. Development upgrades currently underway have presented an opportunity for the relocation of an existing switching station along with the installation of an additional unit, allowing for the introduction of an additional 200 amp 15KV circuit within the Clifton Hill Distribution Circuit, enabling NPEI to divide the load on existing circuits between the two switching stations, facilitating capacity relief and future load growth. Project scope involves the installation of 2-manholes, 2 SF-6 Vista Switchgear, 100M (x6) of 600MCM Main Circuit, 100M (x6) of 2/0 Distribution Circuit. One of the new Switchgear will incorporate an additional un-fused way to provide for the introduction of an additional primary feeder through the development to an NPEI Circuit on Robinson Street dependent on scheduling of additional development, for which the Owner is presently installing 160M of duct-bank to facilitate the additional feeder. Benefits include improved system reliability, reinforcement & capacity increase of the distribution system within the Tourist Core.

Appendix-AA Reference: 14

KM3 Link

Projected load growth of one of our larger commercial customers requires NPEI to off load and reconfigure the KM3 feeder which currently services their property in order to accommodate their needs. This will require the installation of a new 3-phase feeder connection which will link the KM3 to the 12M1, to allow shifting of significant KM3 load to the 12M1.

Appendix-AA Reference: 15

Pin Oak Main Loop

Project scope involves the installation of a 13.8kV, 600A U/G feeder and associated switchgear as well as rebuilding the 200A loop along Pin Oak Drive and Canadian Drive from McLeod to Montrose. This work is required to support the new commercial development in the area.

Appendix-AA Reference: 16

GPI Feeder Build

Project scope includes the construction of a new egress feeder from NWTS, North along Grimsby Road. East along Young Street to South Grimsby Rd. 6 then North to the NPEI-GPI boundary. NPEI existing plant will be relocated to these new poles, which will be framed to accommodate the new GPI circuit. This is a customer demand driven project with GPI being the customer.

Appendix-AA Reference: 17

Thorold Stone Road – Bridge St. Roundabout

Project scope involves the relocation of two pad mount switchgears and associated ducting / cables to accommodate the construction of a new roundabout at the Thorold Stone Rd, Bridge Street, Victoria Ave. intersection. This is a municipality driven relocation request.

Appendix-AA Reference: 18

Jordan Village UG Relocate

Project scope involves the replacement of existing overhead plant to underground construction in order to accommodate road works planned by the Town of Lincoln. This is a municipality driven relocation request.

Appendix-AA Reference: 19

RR20 Relocates for Roundabouts

Project scope involves the relocation of existing overhead plant in order to accommodate road works planned by the Region. This is a municipality driven relocation request.

Appendix-AA Reference: 20

Fallsview UG Relocate

Project scope involves the replacement of existing O/H distribution with relocated U/G along Fallsview Blvd. from Ferry St. to Robinson St. to accommodate Municipality driven road redevelopment.

Appendix-AA Reference: 21

Kalar TS Additional Switchgear

Kalar TS was designed with dual winding power transformers and the capability of supporting two lineups of switchgear. At time of construction only one lineup of switchgear was installed. We have reached capacity on the existing switchgear and need to begin the design process for tendering the installation of the second set of switchgear to utilize the second set of transformer windings and increase the capacity of the station. This project is to complete the detailed design and tender package for the new switchgear.

Appendix-AA Reference: 22

Miscellaneous

These amounts include capital costs that are not charged to a specific project and variations in the level of capitalized inventory such as meters, transformers and switchgear.

Appendix-AA Reference: 23

Crawford St. Rebuild – Thorold Stone to Sheldon

Completion of the Rebuild Project which targets 1.38 kilometers of urban distribution line installed in 1953, including 50 pole changes, new single (880M) & three phase (500M) primary and secondary (1790M) circuits, 10 distribution transformer replacements resulting in the upgraded supply to about 122 residential customers directly, in an area bounded by Drummond Rd., Portage Rd, Sheldon St., St James St., Longhurst Ave, Elberta Ave. & Crawford St. System benefits include replacement of aging equipment, future voltage conversions opportunities, improved equipment clearance, and increased Customer reliability.

<u>Appendix-AA Reference: 24</u>

Willodell Road – Gonder Rd. to Koabel Rd.

Project scope involves replacement/relocation of 1.5 KM. of rural overhead 2.4 KV (RECL-2) off-road primary line with an overhead 15 KV class single phase line relocated within the Willodell Road Allowance between Gonder Rd & Koabel Rd. Installation of 27-new 45' wood poles, 6-25KVA transformer and transfer 8-existing services. System benefits include the replacement of aging equipment originally installed in 1949, constructed on private property, by Ontario Hydro, without registered easements in favor of the Utility, relocation of inaccessible infrastructure, future capability of conversion to 15KV with clearance sufficient to construct 3-phase if required, improved reliability and reduced response time due to improved equipment access.

<u>Appendix-AA Reference: 25</u>

Willoughby Drive – Main St. to Cattell Dr.

Project scope involves the replacement of 1.2 KM. of urban overhead 13.8 KV primary line installed in 1960 with 17-new 45’ wood poles framed for 3-phase, 10-new 40' wood poles framed for single phase and re-conductor the existing 3/0 Lum with 556 MCM 3-phase main circuit, constructed in the same alignment as the existing pole line, install 7-single phase & 1-three phase transformer to replace existing, install 1.1KM of secondary buss, and transfer of 34 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the main distribution line.

Appendix-AA Reference: 26

Willoughby Drive – Cattell Dr. to Weinbrenner Rd.

Project scope involves the replacement of 0.7 KM. of urban overhead 13.8 KV primary line installed in 1969 with 21-new 45’ wood poles framed for 3-phase & 4-new 40' wood poles framed for single phase and re-conductor the existing 3/0 Lum with 556 MCM 3-phase main circuit, constructed in the same alignment as the existing pole line, install 5-single phase & 1-three phase transformer to replace existing, install 1.1KM of secondary buss, and transfer of 30 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement of supply to a sensitive load (large Senior Care Facility).

Appendix-AA Reference: 27

Transformer Replacements – PCB > 50 ppm

The third and final phase of the three-year transformer testing program has been completed in 2014 within the West Service Territory resulting in the requirement to replace approximately 50 units identified as having over the Legislated limit of PCB content. The program will track these change- outs which will likely include the replacement of the pole supporting the unit with associated transfers, removals and disposal costs. Benefits include meeting the requirement of the Legislation, and removal of the hazardous material from the system.

Appendix-AA Reference: 28

Downton Core PILCDTSA Decommissioning

NPEI has targeted lead jacketed primary cable for removal from service, due to age (installed in 1959), performance, and difficulty of performing repairs. The last section in service is located between Station #151 on River Rd and the City Hall Sub-Station located on Huron St. Project scope involves the decommissioning of 1.0 KM. of existing 500MCM PILCDTA direct-burial cable by replacement with a combination of new & existing infrastructure. 350M of new primary duct bank will be installed on River Rd. between Buttrey St. & Bridge St., and a voltage conversion of an existing underground 4.16 KV (F-64) primary line installed in 1995 from the City Hall station to the corner of Bridge Street & River Road. This 2/0 circuit, installed within a concrete encased duct bank, takes a similar route to the lead cable, and can be incorporated into the 15KV system by performing a voltage conversion and tying the 2-systems together at City Hall, and at Bridge St, since the existing 4.16KV Feeder cable is insulated to 15KV, and connected transformers are dual voltage units. System benefits include replacement of infrastructure targeted for decommissioning, the immediate voltage conversion of approx. 500 KVA of connected load from Station #6, improved system losses and performance.

<u>Appendix-AA Reference: 29</u>

Station 22 Rebuild – Phase 1 Carryover / Phase 2

Completion of Phase 1 of the Rebuild Project which targets 1.70 kilometers of urban distribution line installed in 1953, including 58 pole changes, new single (1.70KM) and secondary (1.70KM) circuits, 10 distribution transformer replacements resulting in the upgraded supply to about 125 residential customers directly, in the area bounded by Dorchester Rd., Lundy's Lane, Brookfield Ave, & Coach Dr. System benefits include reconstruction to eliminate Municipal Sub-Station. #22 constructed in 1969, targeted for decommissioning, replacement of aging equipment, future voltage conversions opportunities, improved equipment clearance, and increased Customer reliability

Phase 2 of the Rebuild Project which targets 1.20 kilometers of urban distribution line installed in 1953, including 38 pole changes, new single-phase (1.2KM) & secondary (1.4KM) circuits, 8 distribution transformer replacements resulting in the upgraded supply to about 119 residential customers directly, in the area bounded by Dorchester Rd., Lundy's Lane, Brookfield Ave., & Garden St. System benefits include reconstruction to eliminate Municipal Sub-Station. #22 constructed in 1969, targeted for decommissioning, replacement of aging equipment, immediate voltage conversions opportunities, improved equipment clearance, and increased Customer reliability.

<u>Appendix-AA Reference: 30</u>

Beck Road Rebuild – Marshall Rd. to Schisler Rd.

Project scope involves replacement/relocation of 0.7 KM. of a rural overhead 2.4 KV (RECL-2) off-road primary distribution line, with an overhead 15 KV class single phase line relocated within the Beck Rd allowance between Marshall Rd & Schisler Rd. Installation of 16-new 45' wood poles, 1-25KVA transformer and transfer 5 existing services. System benefits include the replacement of aging equipment originally installed in 1955, constructed on private property, by Ontario Hydro, without registered easements in favor of the Utility, relocation of inaccessible infrastructure, future capability of conversion to 15KV with clearance sufficient to construct 3-phase if required, improved reliability and reduced response time due to improved equipment access.

Appendix-AA Reference: 31

Frederica St. Rebuild – Dorchester Rd. to Drummond Rd.

Project scope involves the replacement of 1.1 KM. of existing 2/0 overhead 4.16 KV (F-104) primary line installed in 1955 with 16-new 45’ wood poles & utilizing 12-existing poles replaced previously and re-conductor the existing with 556 MCM 3-phase main circuit, constructed in the same alignment as the existing pole line, install 4-new transformers, install 1.1KM of secondary buss, and transfer of 55 services to the new buss. Benefits include the final stage of reconstruction to eliminate Municipal Sub-Station #22 constructed in 1969, targeted for decommissioning, the provision for immediate voltage conversion opportunities of several existing lateral feeds, improved system losses, improved equipment clearances.

Appendix-AA Reference: 32

NS&T ROW – Crossing the QEW

Due to a previous pole fire & future MTO widening proposals the need has arisen to replace an existing overhead single pole, double circuit 15KV primary structure crossing the Q.E.W. south of Thorold Stone Road with a double pole structure with removal of the plant located within the MTO R.O.W. This will facilitate the future widening by the MTO utilizing Grade "A" standard construction using concrete poles, increasing Public Safety by eliminating future pole fire possibilities, and constructing to present day standards with increased spacing to facilitate joint-use attachments on the structure.

Appendix-AA Reference: 33

Jordan Rd. Rebuild – Honsberger from Jordan to Thirteenth

The Project Scope involves the second stage of rebuild of existing 3-phase 8320 Volt primary line, in place, constructed to 27.6kV standards for approximately 2.0km involving the installation of 34-new 45' poles on Honsberger Rd from Jordan Rd to Thirteenth St., transfer of existing primary conductors, and installation of 2.0km of new neutral. The project was driven by the pole inspection program which has identified a high number of deteriorated cross arms supporting the primary conductors. Benefits include elimination of the identified hazard, improved equipment clearance, and provisions for future conversion to 27.6kV of the feeders supplied by Jordan M.S. for its eventual de-commissioning.

Appendix-AA Reference: 34

Kalar TS Protection Equipment Refurbishment

Project scope involves Upgrade of Protective Relaying/Communication Equipment in conjunction with upgrades which are currently underway by Hydro One at the Allanburg facility.

Kalar TS Relay Upgrade

Kalar TS was placed in service in 2004. The station consists of 2 x 75 MVA power transformers connected to the Hydro One transmission system at 115kV. The existing relays, RTU, and associated protection and control (P&C) equipment are at end of life and require replacement. Two failures to date have been experienced. These devices were to be replaced with equipment to current day standards. The transfer trip relays were successfully changed in 2018 and one GE F-60 feeder relay changed in 2017. Compatibility issues with the replacement feeder relay were observed and GE has now indicated a resolution to the previous issues. This project is to complete the replacement of one GE feeder F-60 protection relay as well as the design work to replace the station RTU.

Appendix-AA Reference: 35

Dorchester Road Rebuild – McLeod to Dunn

Rebuild Project which targets 1.0 K.M. of urban distribution line installed in 1955, including 26 pole changes, new three phase (1.0KM) primary and secondary (1.0KM) circuits, 5-1Ph. & 3-3 Ph. distribution transformers replacements resulting in the upgraded supply to about 74 residential & 7 Commercial customers directly. System benefits include replacement of aging equipment, future source for voltage conversions opportunities in the immediate area, improved equipment clearance, and increased Customer reliability and capacity increase.

Appendix-AA Reference: 36

Concession 2 Rd. – Caistorville Rd. to Westbrook Rd.

Extension of 1-Phase 4.8kV feeder on Concession 3 Rd., 1-Phase 16kV feeder on Concession 2 Rd. and rebuild of 4 poles for 1-Phase 4.8kV feeder on Green Rd. within the road allowances to facilitate removal of 35 poles and approximately 3km of feeder from inaccessible farm fields. The existing plant which was not installed in the municipal road allowance, was installed in the 1940's and is at end of life.

Appendix-AA Reference: 37

Thorold Stone Road – Montrose to Kalar

Project scope involves the replacement of 1.1 KM. of urban overhead 13.8 KV primary line installed in 1958 with 27-new 45' wood poles, constructed in the same alignment as the existing pole line. Replacement of the undersized primary conductor with 556 MCM for increased ampacity of the circuit during contingency situations, 6-single phase transformers to replace existing, transfer 4-three phase & 2-single phase primary risers, install 1.1.KM of secondary buss, and transfer of 40 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area.

Appendix-AA Reference: 38

Portage Road Rebuild – Mountain to Church's Lane

Project scope involves the replacement of 0.6 KM. of urban overhead 13.8 KV 3-phase primary line installed in 1966 with 17-new 45’ wood poles, constructed in the same alignment as the existing pole line to provide a tie point between the 12-M-1 and the 12-M-4 from Stanley T.S. Replacement of the undersized primary conductor with 556 MCM for increased ampacity of the circuit during contingency situations, 3-single phase transformers to replace existing, transfer 2-single phase & 2-three phase primary risers, install 0.6 .KM of secondary buss, and transfer of 46 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area with redundancy provisions.

Appendix-AA Reference: 39

Campden DS Power Tx – Replace with Former Jordan DS Tx

Project scope involves removal, transportation, and replacement of the 5000kVA Power Transformer located at the Distribution Sub-Station. Under previous refurbishments the switchgear line-up and supply cables were upgraded, and the compound is equipped with an oil containment structure. The Station Transformer has been targeted to be replaced with the Power Transformer from Jordan D.S., once all phases of the conversion work have been completed. The Station Transformer was manufactured in 1972 and has bushing gasket issues and metal particulate in the tap-changer compartment oil.

Appendix-AA Reference: 40

Station DS - Power Tx Replace

Project scope involves removal, transportation, and replacement of the 5000 KVA Power Transformer located at the Distribution Sub-Station. Under previous refurbishments the switchgear line-up and supply cables were upgraded, and the compound is equipped with an oil containment structure. The Station is one of two stations supplying the Town of Fonthill at 4.16KV without provisions for voltage conversion, due to Hydro One controlled supply points. The Station Transformer was manufactured in 1969.

Appendix-AA Reference: 41

Station 14 Voltage Conversion

Phase 1

Rebuild Project which targets 1.20 kilometers of urban distribution line installed in 1956, including 34 pole changes, new three-phase (1.2KM) & secondary (1.2KM) circuits, 8-single & 2-Three phase distribution transformer replacements resulting in the upgraded supply to about 86 residential & 2-commercial customers directly, in the area bounded by Dunn St from Dorchester Rd to Drummond Road. System benefits include reconstruction to eliminate a Municipal Sub-station (Station #14 constructed in 1956, targeted for decommissioning), replacement of aging equipment, immediate voltage conversions opportunities for approximately 800KVA of connected load, improved equipment clearance, and increased Customer reliability.

Phase 2

Rebuild Project which targets 1.20 kilometers of urban distribution line installed in 1956, including 83 pole changes, new three-phase (0.4KM @ 14 poles) new single phase (2.0KM @ 52 poles) & secondary (3.0KM @ 17 poles) circuits, 19-single phase distribution transformer replacements resulting in the upgraded supply to about 256 residential customers directly, in the area bounded by Drummond Rd, Skinner St, Dell Ave, Hawkins St, Arad St, Churchill St, Atlee St & Margaret St. System benefits include reconstruction to eliminate Municipal Substation Station. #14 constructed in 1956, targeted for decommissioning, replacement of aging equipment, immediate voltage conversions opportunities for approximately 800KVA of connected load, improved equipment clearance, and increased Customer reliability.

Phase 3

Rebuild Project which targets 2.5 kilometers of urban distribution line installed in 1956, including 76 pole changes, new single phase (2.0KM @ 62 poles) & secondary (2.5KM @14 poles) circuits, 18-single phase distribution transformer replacements resulting in the upgraded supply to about 250 residential customers directly, in the area bounded by Hagar Ave, Caledonia St, Winston St, Concord Cres, Demetre Cres, Argyll Cres &

Paisley Ave, &Jolley Cres. System benefits includes the final stage of reconstruction to eliminate Municipal Sub-station. #14 constructed in 1956, targeted for decommissioning, replacement of aging equipment, immediate voltage conversions opportunities for approximately 800KVA of connected load, improved equipment clearance, and increased Customer reliability.

Appendix-AA Reference: 42

Victoria Ave. South of Fly Road

The Project Scope involves the overbuild of an existing 3-phase 8.2 KV primary line on Victoria Ave in place, and constructed with a 3-phase 27.6KV top circuit for approximately 2.0 KM.

Construction involves the installation of 32-new 45’ poles, transfer of existing primary cable, and installation of 2.0KM of new 556MCM Primary and Neutral conductor from Fly Rd South to Seventh Ave. The Project is being initiated to provide a 27.6KV tie to town of Jordan Station. Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration by tying the F-1 Feeder from Vineland D.S to the M-5 Feeder from NWMTS.

Appendix-AA Reference: 43

Oakwood Drive – South of Smart Centre to QEW

Project scope involves replacement of 1.5 KM. of an urban overhead primary distribution line, with an overhead 15 KV 600-amp class main 3-phase line in the same alignment as the existing. Installation of 25-new 50' wood poles, 7-Single Phase, 2-Three Phase transformers, transfer 3-three phase & 1-Single Phase Underground Primary Risers, and transfer 24-existing Residential triplex services. Since the original install this section of line has changed function from a radial feed, and has been incorporated into a tie between 2-Transformer Stations, without re-conductoring to facilitate the ampacity increase. System benefits include the replacement of aging equipment originally installed in 1970, system loss reduction, improved reliability, and capacity increase.

Appendix-AA Reference: 44

Dorchester Road Rebuild – Mountain to Riall

Project scope involves the replacement of 1.0 KM. of urban overhead 13.8 KV primary line installed in 1952 with 20-new 45' wood poles, constructed in the same alignment as the existing pole line, install of 200m of concrete encased duct-bank under a major Transmission Corridor due to clearance issues with the transmission line to an overhead line. Replacement of the undersized primary conductor with 556 MCM for increased ampacity of the circuit during contingency situations, 4-single phase transformers to replace existing, install 0.6KM of secondary buss, and transfer of 40 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area.

Appendix-AA Reference: 45

Chippawa Redundant Supply

Phase 1

Project scope involves rebuild/reinforcement of 1.4 KM. of an existing rural overhead primary distribution line, on Stanley Ave from Lyons Creek Rd to Rexinger Rd, Rexinger Road from Stanley Ave to Ort Rd--Ort Rd from Rexinger Rd to Willick Rd, incorporating 12-new pole installs and salvaging poles upgraded by the Pole Replacement Program. NPEI will re-conductor the existing 1/0 Aluminum Primary with 556 MCM Aluminum for the required capacity increases. This Project will enable NPEI to target the removal of a sub-standard aerial primary Welland River Crossing feeding into the Village of Chippawa. System benefits include improved reliability, inter-tie capabilities between the 3-M-27 & 3-M-56 Feeders sourced from the Murray T.S.

River Crossing

Project scope involves the replacement of 0.75 KM. of urban overhead 13.8 KV 3-phase primary line along Reilly St., across the Chippawa River to Sophia St. Includes the replacement of end of life steel structures supporting the river crossing with concrete poles. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area with redundancy provisions.

<u>Appendix-AA Reference: 46</u>

Murray TS – J Bus Metering

Existing wholesale metering for the J-Bus at Murray TS is on the Measurement Canada Dispensation list as it does not meet current metering standards. This metering is required to be upgraded to current standards prior to the end of 2020. This project addresses this issue by installing individual feeder level wholesale meter points outside of the station similar to what NPEI has done previously with the Y-Bus feeders.

<u>Appendix-AA Reference: 47</u>

Victoria Ave. Rebuild – 7th Ave Phase 2

The Project Scope involves the rebuild of existing 3-phase 8.2 KV primary line on Victoria Ave in place, and constructed to 3-phase 27.6KV for approximately 2.0 KM from Fly Rd going South.

Construction involves the installation of 32-new 45' poles, transfer of existing primary cable, and installation of 2.0KM of new Neutral conductor on Seventh Avenue from the Victoria Avenue to Nineteenth St. The Project is being initiated to provide a 27.6KV tie between Vineland Station F-1 to the M-5 from MWMTS Station Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration.

<u>Appendix-AA Reference: 48</u>

Campden DS Transformer Failure

During July 2018, the power transformer at Campden DS suffered an internal failure. This transformer had a history of previous failure, and has been repaired twice previously. Given the poor history of performance with this transformer, the decision was made to replace this transformer with a new one. NPEI's portable substation was utilized to provide the transformation at Campden DS pending installation of a new power transformer in 2019.

Appendix-AA Reference: 49

Mountain Road – St. Paul to Mewburn

Phase 1: St. Paul to Dorchester

Project scope involves the replacement of 0.95km of urban overhead 13.8kV 3-phase primary line installed in 1966 with 16-new 45' wood poles, constructed in the same alignment as the existing pole line to provide a tie point between the 12-M-1 from Stanley T.S. and the K-M-3 from Kalar M.T.S. Replacement of the undersized primary conductor with 556kcMIL for increased ampacity of the circuit during contingency situations, 5-single phase transformers to replace existing, transfer 4-single phase primary risers, install 0.9km of secondary buss, and transfer of 19 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement and capacity increase of the supply in the area with redundancy provisions.

Phase 2: Dorchester to Mewburn

Project scope involves the replacement of 0.9km of urban overhead 13.8kV 3-phase primary line installed in 1966 with 21-new 45' wood poles, constructed in the same alignment as the existing pole line which will eventually supply a crossing over the QEW to provide a tie point between the 12-M-1 from Stanley T.S. and the K-M-3 from Kalar M.T.S. Replacement of the undersized primary conductor with 556kcMIL for increased ampacity of the circuit during contingency situations, 2-single phase transformers to replace existing, transfer 3-single phase primary risers, install 0.5km of secondary buss, and transfer of 6 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area with redundancy provisions.

Appendix-AA Reference: 50

Sinnicks Ave Rebuild – Thorold Stone to Swayze

Project scope involves the replacement of 1.2km of urban overhead double 4.16kv circuits (built in 1949). The new pole line will consist of a single 3 phase 13.8kV circuit to connect the 12M43 to the 12M5 feeders as well as a single 3 phase 4.16kV circuit (under build) to connect the F183 (Swayze DS) to F176 (Virginia DS). The new double circuit pole line will consist of 34-new 55' wood poles, constructed in the same alignment as the existing pole line. The side streets (Keith St, Coholan St, Vine St, Harold St, Brooks St, Frances St, Carman St, Atlas St, Judith St) supplied from the existing double circuits have been previously rebuilt to 13.8kV utilizing dual voltage transformers which would be converted to 13.8KV upon completion of the rebuild. The project also includes a section of new underground primary consisting of a new 150m long concrete encased duct-bank from Swayze Drive to Sinnicks Ave for the 600Amp supply from the 12-M-43, and a 130m of cable replacement from Station #179 to Sinnicks Ave for the 600Amp supply from the 12-M-5. Benefits include improved system losses, Public & Personnel safety, improved equipment clearances, reinforcement and capacity increase of the supply in the area with redundancy provisions.

Appendix-AA Reference: 51

McRae St. Area Rebuild – Phase 1

Overall project scope involves the replacement of a single three phase 4.16kV circuit (0.75km) plus 2.25km of a single phase 2.4kV circuit (built in 1960). The new overhead line will be constructed to 13.8kV standards with dual voltage transformers using 25-new 45' and 60-new 40' wood poles. Construction will assume the same alignment as the existing pole lines and include the following side streets; Second Ave, Third Ave, Stuart Ave, Fourth Ave, Heywood Ave, Florence, Detroit Ave, Ottawa Ave, Buchanan Ave, Stamford St, McRae St and Rosedale Dr. The area will be connected to the 13.8kV system at a future date. The project will include replacement of 26-single phase transformers, installation of 3kM of secondary bus and direct transfer of 465 residential services to the new bus. Due to the size of this project, it will be split into three phases.

Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area.

Appendix-AA Reference: 52

King St. Rebuild – Bartlett Road to Sann Rd.

The Project Scope involves the rebuild of existing double circuit 3-phase 27.6kV and 8.32 kV primary line on King St in place, for approximately 1.0km from Bartlett Rd going East to Sann Road. Construction involves the installation of 18-new 55' poles for double circuit, transfer of existing primary cable on the 8.32kV, and installation of 1.0km of new 556kcMIL primary & 3/0 Neutral conductor with 3/0 spun bus. The Project is being initiated to provide a capacity increase on the 27.6kV tie between the F1 (Vineland DS) and 18M1 (Beamsville TS) and replace end of life equipment identified through NPEIs Asset Condition Assessment. Benefits include improved supply reliability and flexibility on the system during contingencies and system configuration.

Appendix-AA Reference: 53

Pole Replacements

The natural degradation of wooden utility poles is an ongoing issue. NPEI performs a site visit of every distribution pole on the System as per OEB requirements (3 years/urban, 6 years/rural), with a total population of over 37,000. The pole is tested for its integrity, a visual inspection is performed of the equipment installed on the pole by qualified Linesmen, the pole is imaged, guy guards are installed & down grounds are repaired/replaced as required, and the inspection results and images are stored within the Geographical Information System (GIS). An evaluation of the results is performed, with deficiencies addressed by the replacement of deficient poles, in a timely manner, through this Capital Program.

Appendix-AA Reference: 54

Kiosk Replacements

Prior to the advent of pad-mounted Transformer & Switchgear Equipment, supplying loads larger than could be supplied by pole mounted equipment, or areas serviced from underground primary distribution systems, lead to the development of ground mounted masonry enclosures housing high voltage transformation, switching & protection apparatus, and secondary distribution equipment, known as the Kiosk. These block structures were meant to provide Public Safety but over time, the structures deteriorate and warrant replacement. These are prioritized utilizing the results of a 5-year Conditional Assessment Survey last completed in 2019. This Capital Program is an integral part of the remediation of underground distribution systems, increasing longevity and reliability within the area serviced. As these legacy components are replaced, safety, reliability and service quality are significantly improved.

<u>Appendix-AA Reference: 55</u>

Switchgear Replacements

The Underground Equipment Inspection Program has identified a requirement for replacement of air insulated pad-mounted switchgear units, with dead-front stainless steel enclosure SF-6 Gas Insulated Equipment, due to corrosion and contamination issues. Project scope involves the installation of applicable civil works such as manholes and duct-banks associated with the equipment replacement to current standards, using equipment constructed of Stainless Steel to avoid corrosion issues. Increased system reliability, Public & Personnel safety, and functionality are benefits of the program.

<u>Appendix-AA Reference: 56</u>

Polemount Stepdown Transformer Eliminations

Project scope involves the replacement of 1.8 km of overhead single three phase 8.32kV circuit (built in 1960) with a single three phase 27.6kV circuit using 28 - new 45' wood poles, constructed in the same alignment as the existing pole line along Ninth Street. The project includes relocation of a bank of step-down transformers from south of Fourth Avenue to south of King Street and installation of a new single phase step-down transformer on King Street west of Ninth Street along with replacement of 15-single phase transformers, installation of 1km of secondary bus, and direct transfer of

33 residential services to the new bus. Benefits include improved system losses, improved equipment clearances, reinforcement, Public & Personnel safety, and capacity increase of the supply in the area.

Appendix-AA Reference: 57

Rolling Acres OH to UG Conversion Phase 2

Phase II project scope involves the relocation of primary facilities located on an inaccessible rear lot pole line within private property, for which easement documentation is available. 1.0KM of Primary duct by directional boring technology to 5 pad-mounted transformers placed on precast pads within the Road Allowance. Secondary laterals will be directionally bored back to the rear lot easements, to source the 55 individual underground house services currently fed from junction boxes mounted on the distribution poles. The streets included within this Phase include Oxford, McColl Drive, Cambridge Street, Rolling Acres Drive. The current equipment was installed in 1961 and tree growth, pool, shed and fencing installations, have made the line difficult to maintain and service. There have been many issues in this subdivision during Ice/Wind Storms. 15KV rated equipment will be installed for future voltage conversion, once all the phases have been completed.

Rolling Acres OH to UG Conversion Phase 3

The final stage of the project scope involves the relocation of primary facilities located on an inaccessible rear lot pole line within private property, for which easement documentation is available. Installation of 2.0KM of Primary duct by directional boring methods to 9 pad-mounted transformers placed on precast pads within the Road Allowance. Secondary laterals will be directionally bored back to the rear lot easements, to source the 100 individual underground house services currently fed from junction boxes mounted on the distribution poles. The streets included within this Phase include Potter Heights, Cambridge St., McColl Dr., and Rolling Acres Drive & Rolling Acres Cres. & Wiltshire Blvd. The current equipment was installed in 1958 and tree growths, pool, shed and fencing installations, have made the line difficult to maintain and service. There have been many issues in this subdivision during Ice/Wind

Storm events. 15KV rated equipment will be installed for voltage conversion, once this phase has been completed. Improved Public safety, equipment accessibility, capacity increase, and voltage conversion are benefits realized through this Project.

Appendix-AA Reference: 58

Stanley TS – HONI Initiated

HONI is rebuilding half of their Stanley TS infrastructure, including a new power transformer, P&C building and switchgear for the B-Y bus. The HONI initiated work will result in NPEI installing new feeder egress on all 4 feeders connected to the B-Y bus along with new primary metering on each feeder. Current bus level metering on the J-Q bus must be converted to feeder level metering as per the IESO. All 6 feeders connected to the J-Q bus will require new primary metering on each feeder. All work is to be coordinated with HONI project schedule.

Appendix-AA Reference: 59

Subdivision Rehabilitation

Establishment of this Capital Program provides a solution, to a problem identified during the last Asset Condition Assessment, for replacement of directly buried primary & secondary conductors supplying residential services within the oldest Underground Distribution Residential Subdivisions within the Niagara Falls Service Territory. The original installations were duct-less, making replacement difficult and costly. To extend lifecycles of the infrastructure NPEI recently completed a Program to replace the Submersible Transformers with Pad-mount Transformers. The program began in 1994 with approximately 400 units converted. Sections of primary cable within the submersible enclosure, damaged by poor heat dissipation were spliced out and re-terminated, preventing failure. The cable was manufactured to a 133% insulation level, prolonging the life cycle; however, without a base value to compare the results of any cable testing, it is difficult to determine degradation since its installation. Expected lifespan of the cable is 35 years. To correct a noted deficiency in last Asset Assessment NPEI has entered installation dates, within the GIS, from as-built drawings, to help in prioritizing future replacement. The program would facilitate the installation, by directional boring methods, of a 4" & 3" HDPE conduit on the side of the road where primary and secondary co-exist, and a 4" HDPE conduit where only secondary is installed between all pad-mount foundations. Existing Cable would be "run to failure", at which time new cable would be installed under the Sustainment budget. The first subdivision targeted was installed in 1967.

Appendix-AA Reference: 60

King St. 27.6 kV Extension to Martin Rd.

The Project Scope involves the rebuild of existing 1-phase 16KV primary line west of Martin Ave to the 3-phase dead-end, in place, and constructed to 3-phase 27.6KV for approximately 280 M. Construction involves the installation of 8-new 45’ poles, transfer of 1-primary riser, and installation of 165 m of new 3-phase from Rittenhouse Road to Martin Rd, and removal of 6-existing poles. Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration.

Appendix-AA Reference: 61

Heartland Rd. Extension – Brown Rd. to Chippawa Creek

Project scope involves extension of 0.4 KM. of an urban overhead primary distribution line, including the installation of 8 new 45' poles, framing & stringing of 556 MCM primary conductor to tie between 2-previous line builds to service a new low lift pumping station and a Regional Bio-Solids Treatment facility. System benefits include improved reliability, inter-tie capabilities between the K-M-6 & K-M-2 Feeders sourced from the Kalar M.T.S and the 3-M-30 from Murray T.S.

Appendix-AA Reference: 62

Grid Modernization Program

Installation of smart technologies onto the distribution system. These technologies include reclosers, fault indicators and switches. These devices will communicate real time system status to our Operators allowing them to make better decisions when operating the system. The devices will also be remotely operable by the Operators via our existing WiMax network. This will be an annual program which focuses on modernizing our distribution system to improve both system reliability and efficiency.

Appendix-AA Reference: 63

Glenholme to Franklin Ave. – 600 MCM UG Install

Project scope involves the installation of 150M of 600MCM Underground 15 KV primary cable to complete an inter-tie between two recently completed system rebuild/upgrades. Installation of 100m of new concrete encased duct bank tied into 50M of existing duct bank, install 160M x 3 of 600mcm underground primary cable and completion of 2-primary risers. System benefits include increased flexibility during failure contingency periods, and the ability to reconfigure the system based on the results of optimization studies using system modeling software.

Appendix-AA Reference: 64

Brown Road Extension – Montrose to Blackburn

Project scope involves extension of 1.2 KM. of an urban overhead primary distribution line, overbuilt on a wooden pole line built by Bell Canada in 2008 at which time NPEI had Bell install 13-poles with additional height from 35' to 45'. The framing & stringing of this section of line will be incorporated into a tie between 2-previous line builds to service a new low lift pumping station and an Industrial Subdivision owned by the City of Niagara Falls. System benefits include improved reliability, inter-tie capabilities between the K-M-6 & K-M-2 Feeders sourced from the Kalar M.T.S and the 3-M-30 from Murray T.S.

Appendix-AA Reference: 65

Range Road 2 – East of Allen

Project scope involves extension of 0.66KM. of a rural overhead primary distribution line between pole #43518 & pole #43581 to replace 0.5KM of distribution line presently located on an opened road allowance with poor access. Install 13-new 40' wooden poles. The framing & stringing of this section of line will tie to a line within the Road Allowance of Range Road 2. System benefits include improved reliability an emergency response, with removal of inaccessible line upon completion.

<u>Appendix-AA Reference: 66</u>

System Sustainment / Minor Betterments

This Capital Program manages an allowance for minor projects initiated by unexpected failures/deficiencies of overhead and underground distribution facilities. Replacement of underground cable experiencing repeated failures is a major contributor covered by this allowance. Minor overhead system modifications and component replacements are also accounted for.

<u>Appendix-AA Reference: 67</u>

Willoughby Road Extension

Willoughby Rd from Weinbrenner to Willick. This project builds on previous re-build work completed on Willoughby Rd starting in 2015 and is a continuation of the aim to reinforce supply to the Chippawa Area of Niagara Falls to support new growth. Includes installation of 11-new 45' wooden poles and approx. 240m of duct to traverse under the CNP right of way.

<u>Appendix-AA Reference: 68</u>

Kalar TS Power Transformer Dry Down Equipment

Oil analysis for the power transformers at Kalar TS have been indicating unacceptably high levels of moisture content which if left untreated can shorten the anticipated asset life. This project is to cover the cost of purchasing and installing an on-line oil dry down system to remove the moisture from the oil and prolong transformer life.

<u>Appendix-AA Reference: 69</u>

Greenlane Road at Ontario – Tie Point

Project scope involves the installation of approximately 0.25km of 1000kcMIL underground primary cable in a new concrete encased duct-bank to create a tie on the 18M4 (Beamsville TS) system north of CN Rail Tracks and 18M1 (Beamsville TS) on Ontario Street & Greenlane Rd. Benefits include increased Customer reliability during contingencies, capacity increase for the area and reduced system losses.

Table 2.2.2.2 below provides a summary of NPEI's capital projects and programs each year, by investment category.

Table 2.2.2.2 – Summary by Investment Category

Category	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge	2021 Test
System Access	7,462.92	6,489.73	5,701.04	5,992.90	7,973.76	9,487.57	8,465.68
System Renewal	4,176.06	5,625.55	5,534.91	5,256.22	4,031.84	4,246.68	6,828.18
System Service	1,844.56	1,732.73	1,258.51	1,391.88	1,572.46	1,201.75	1,097.81
General Plant	1,538.20	1,578.42	2,438.55	2,344.91	3,369.13	2,628.20	1,550.98
Total	**15,021.73**	**15,426.43**	**14,933.02**	**14,985.91**	**16,947.19**	**17,564.20**	**17,942.66**

Year-over-year variance analysis by investment category is provided below.

Table 2.2.2.3– 2016 Actual vs 2015 Actual

Category	2015 Actual	2016 Actual	Variance 2016 Actual vs 2015 Actual
System Access	7,462.92	6,489.73	(973.18)
System Renewal	4,176.06	5,625.55	1,449.49
System Service	1,844.56	1,732.73	(111.83)
General Plant	1,538.20	1,578.42	40.22
Total	**15,021.73**	**15,426.43**	**404.70**

System Access

System Access costs for 2016 Actual were ($973K) lower than 2015 Actual.

Prior to 2015, NPEI had not recorded the cost of expansion facilitates transferred from customers which were constructed under the alternative bid option provided for in Section 3.2 of the Distribution System Code.

In 2015, NPEI recorded $3.1M in transferred assets, with offsetting capital contributions, which related to subdivisions energized between 2011 and 2015. In 2016, NPEI recorded $688K in transferred assets, resulting in lower expansion facilities transferred from customers of ($2,471K) compared to 2015 Actual.

New commercial services were $295K higher in 2016, and subdivisions were $202K higher.

During 2016, there was a large wind farm facility installed in NPEI's service area. As a result, NPEI had to relocate distribution plant to accommodate the new generation facility. The costs for these line relocations were $1,528K, all of which was recovered in capital contributions paid by the wind farm developer.

Municipal road relocations were ($811K) lower than 2015 Actual. Material road relocation projects in 2015 are: Regional Municipality of Niagara – Regional Road #18 – Mountain Road for $311K and City of Niagara Falls Level St. Relocate for $231K. There were no material road relocation projects in 2016.

System Renewal

System Renewal costs for 2016 Actual were $1,149K higher than 2015 Actual, mainly attributable to Overhead Rebuilds higher by $513K in 2016 and Kiosk Replacements higher by $854K.

There were 5 material rebuild projects in 2015:

- Crawford St. Rebuild – Thorold Stone to Sheldon = $463K
- Willodell Road – Gonder Rd. to Koabel Rd. = $313K
- Station 22 Rebuild – Phase 1 Carryover = $682K
- Beck Road Rebuild – Marshall Rd. to Schisler Rd = $171K
- Jordan Rd. Rebuild – Honsberger from Jordan to Thirteenth Phase 2 = $460K

There were 7 material rebuild projects in 2016:

- Willoughby Drive – Main St. to Cattell Dr. = $459K
- Willoughby Drive – Cattell Dr. to Weinbrenner Rd. = $375K
- Station 22 Rebuild – Phase 2 = $203K
- Frederica St. Rebuild – Dorchester Rd. to Drummond Rd. = $690K
- NS&T ROW – Crossing the QEW = $207K
- Jordan Rd. Rebuild – Honsberger from Jordan to Thirteenth Phase 3 = $307K
- Dorchester Road Rebuild – McLeod to Dunn = $377K

Several Kiosk Replacements that were deferred from 2015 were completed in 2016:

- 2015 Kiosk Replacement budget = $647K; 2015 Actual = $311K; Variance = ($336K).
- 2016 Kiosk Replacement budget = $841K; 2015 Actual = $1,166K; Variance = $325K.

System Service

System Service costs for 2016 Actual were $112K lower than 2015 Actual.

General Plant

General Plant for 2016 actual was $40K higher than 2015 Actual.

Table 2.2.2.4 – 2017 Actual vs 2016 Actual

Category	2016 Actual	2017 Actual	Variance 2017 Actual vs 2016 Actual
System Access	6,489.73	5,701.04	(788.69)
System Renewal	5,625.55	5,534.91	(90.63)
System Service	1,732.73	1,258.51	(474.22)
General Plant	1,578.42	2,438.55	860.13
Total	**15,426.43**	**14,933.02**	**(493.42)**

System Access

System Access costs for 2017 Actual were ($788K) lower than 2016 Actual.

Wind farm relocation costs of $1,528K in 2016 did not recur in 2017.

Metering costs for 2017 Actual were $463K higher than 2016 Actual.
In 2014, the Ontario Energy Board provided notice of amendments to the Distribution System Code ("DSC") pursuant to section 70.2 of the Ontario Energy Board Act, 1998. The DSC amendments provide notice that a distributor is required to install an interval meter (i.e. a "MIST" meter) on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW. The DSC requires that MIST meters are to be installed by August 21, 2020. NPEI's 2015 COS Rate Application (EB-2014-0096) included an estimate of 915 conventional meters to be replaced between 2015 and 2020.NPEI commenced the replacement of conventional meters with MIST meters during 2016, continuing in 2017.

The Metering costs for 2017 Actual also include the replacement of 201 interval meters which used legacy 2G cellular communication technology. In the spring of 2017, NPEI received notification from the vendor which provided intermediate communication service for these meters that they would no longer support the metering communication system due to it becoming obsolete in the cellular domain. NPEI identified 225 meters that utilized the 2G network to be replaced in order to avoid possible communication disruptions to these meters that provide energy metering to large commercial customers. NPEI completed 201 of the 2G meter changes in 2017, with the remaining 24 meter changes completed in 2018.

System Renewal

System Renewal costs for 2017 Actual were ($91K) lower than 2016 Actual.

System Service

System Service costs for 2017 Actual were $474K lower than 2016 Actual.
The difference is largely related to NPEI's Grid Modernization Program. During, 2016 NPEI installed a Wi-Max communications tower at Campden DS in 2016 at a cost of $115K. During 2017, this cost was reclassed from Communication Equipment to Building, to more accurately reflect the estimated useful life of the tower.

General Plant

General Plant for 2017 Actual was $860K higher than 2016 Actual, largely related to Building and Software.

Building expenditures in 2017 include:

- $173K for a new Wi-Max communications tower in Niagara Falls.
- The Wi-Max communications tower that was installed at Campden DS in 2016 at a cost of $115K was reclassed from Communication Equipment to Building in 2017, to more accurately reflect the estimated useful life of the tower.

Computer Software additions for 2017 include: Outage Management System upgrades for call taker and a mobile component, upgrade to the outage map, 2 GIS licenses, upgrade of Great Plains accounting system, enhancements to the CIS for change of contacts and Class A, and security upgrades for scan of documents for viruses.

Table 2.2.2.5 – 2018 Actual vs 2017 Actual

Category	2017 Actual	2018 Actual	Variance 2018 Actual vs 2017 Actual
System Access	5,701.04	5,992.90	291.86
System Renewal	5,534.91	5,256.22	(278.69)
System Service	1,258.51	1,391.88	133.36
General Plant	2,438.55	2,344.91	(93.64)
Total	**14,933.02**	**14,985.91**	**52.89**

System Access

System Access costs for 2018 Actual were $292K higher than 2017 Actual, largely due to an increase in new commercial services.

System Renewal

System Renewal costs for 2018 Actual were ($278K) lower than 2017 Actual, largely due to a decrease in Kiosk Conversions of ($818K) and a decrease in Pole Replacements of ($127K), partly offset by an increase in overhead rebuilds of $900K.

During 2018, NPEI reduced the targeted Kiosk Conversions compared to 2017, in order to complete several planned overhead rebuilds.

Material overhead rebuild projects in 2018 include:

- Station 14 Voltage Conversion Phase 2 = $713K
- Victoria Ave. South of Fly Road Phase 1 = $694K
- Victoria Ave. South of Fly Road Phase 2 = $568K
- Oakwood Drive - South of Smart Centre to QEW = $584K
- Dorchester Road Rebuild – Mountain to Riall = $205K
- Chippawa Redundant Supply – River Crossing = $492K

System Service

System Service costs for 2018 Actual were ($133K) lower than 2017 Actual.

General Plant

General Plant for 2018 Actual was ($93K) lower than 2017 Actual.

Table 2.2.2.6 – 2019 Actual vs 2018 Actual

Category	2018 Actual	2019 Actual	Variance 2019 Actual vs 2018 Actual
System Access	5,992.90	7,863.44	1,870.54
System Renewal	5,256.22	4,031.84	(1,224.38)
System Service	1,391.88	1,682.78	290.90
General Plant	2,344.91	3,369.13	1,024.22
Total	**14,985.91**	**16,947.19**	**1,961.29**

<u>System Access</u>

System Access costs for 2019 Actual were $1,871K higher than 2018 Actual, largely due to an increase in subdivisions of $964K and an increase in the transfer of expansion facilities form customers of $1,398K, offset by a decrease in metering costs of ($104K).

<u>System Renewal</u>

System Renewal costs for 2019 Actual were ($1,224K) lower than 2018 Actual, largely due to a decrease in Overhead Rebuilds of ($1,629K) and a decrease in Subdivision Rehabilitation of ($381K), partly offset by an increase in Switchgear Replacements of $144K, and Murray Station J-Bus Metering of $430K.

Material overhead rebuild projects in 2019 include:

- Portage Road Rebuild – Mountain to Church's Lane = $288K
- Station 14 Voltage Conversion Phase 3 = $816K
- Victoria Ave. Rebuild 7th Ave. Phase 2 = $232K
- Mountain Road - St. Paul St. to Mewburn = $297K

System Service

System Service costs for 2019 Actual were $291K higher than 2018 Actual, largely due to an increase in System Sustainment of $343K.

General Plant

General Plant for 2019 Actual was $1,024K higher than 2018 Actual, largely due an increase in building costs of $1,013K, representing the first phase of construction of NPEI's new garage and truck washing facility.

The existing vehicle service garage was designed and constructed within the operations centre at 7447 Pin Oak Drive in 1984 (35 years ago) and was sized and outfitted with equipment that accommodated the requirements of the company fleet complement of the day. Future considerations of the physical size of vehicles and the number of fleet equipment were incorporated into the design at that time, but those capacities and numbers have been exceeded for some years now. On average, the size and weight of the large service vehicles has increased by 30 to 40 percent and the number of vehicles in the fleet has doubled since the garage was designed and built. The garage is now too small to provide for the needed space to service the number of vehicles we have, and the limited capacities of the vehicle hoisting systems have been reached and they are near the end of their useful life. To maintain safe and efficient servicing for our fleet of equipment a new facility is required.

The new Service Garage facility will provide space to accommodate up to, two large and two small vehicles at one time (twice the existing capacity). The hoisting systems will have greater lifting capacities and will incorporate the latest safety technologies. Environmental management features will be incorporated where required and energy efficient systems will be installed to be environmentally responsible and respectful. The new service facility will provide a modern, safe, efficient and environmentally friendly environment to service our complement of vehicles and will support our equipment servicing requirements for decades to come.

Included in the new service garage facility building footprint will be a roughed in truck washing bay. Currently all vehicle washing is performed in the large vehicle parking garage. Washing vehicles in this area results in a perpetually wet environment that creates slipping hazards and accelerates the degradation of the concrete floor. It is anticipated the truck washing facilities will be installed in the future.

Table 2.2.2.7 – 2020 Bridge vs 2019 Actual

Category	2019 Actual	2020 Bridge	Variance 2020 Bridge vs 2019 Actual
System Access	7,973.76	9,487.57	1,513.80
System Renewal	4,031.84	4,246.68	214.84
System Service	1,572.46	1,201.75	(370.71)
General Plant	3,369.13	2,628.20	(740.93)
Total	**16,947.19**	**17,564.20**	**617.01**

System Access

System Access costs for the 2020 Bridge Year is $1,514K higher than 2019 Actual, due to an increase in municipal road relocations of $2,156K an increase in new commercial services of $1,562K, GPI Feeder Build of $807K, offset by a decrease in the transfer of expansion facilities from customers of ($1,312K), and a decrease in subdivision costs of ($1,083K).

Material System Access projects in 2020 include:

- KM3 Link = $877K
- Pin Oak Main Loop = $1,224K
- GPI Feeder Build = $807K
- Thorold Stone Rd. – Bridge St. Roundabout = $452K
- Jordan UG Relocate = $1,063K
- Regional Road 20 Roundabouts - $255K
- Fallsview UG Relocate = $452K

NPEI anticipates that the level of subdivision development in 2020 will return to a level more typical of recent years compared to 2019.

System Renewal

System Renewal costs for the 2020 Bridge Year are $215K higher than 2019 Actual, mainly due to an increase in Overhead Rebuilds of $853K, a decrease in Pole Replacements of ($262K), and a decrease in Switchgear Replacements of ($223K).

System Service

System Service costs for the 2020 Bridge Year are ($371K) lower than 2019 Actual, largely due to a decrease in System Sustainment of ($401K).

General Plant

General Plant for the 2020 Bridge Year is ($741K) lower than 2019 Actual, mainly due to:

- A decrease in building costs of ($270K), as NPEI expects the new garage building to be completed in 2020.
- A decrease in vehicle costs of ($410K). Vehicle expenditures in 2019 include the replacement of a pick-up truck for $40K, chassis for a radial boom derrick for $264K, and a mini-track machine for $248K. In 2020, NPEI plans to replace a van for $40K and purchase the chassis of a bucket truck for $150K.

Table 2.2.2.8 – 2021 Test vs 2020 Bridge

Category	2020 Bridge	2021 Test	Variance 2021 Test vs 2020 Bridge
System Access	9,487.57	8,465.68	(1,021.88)
System Renewal	4,246.68	6,828.18	2,581.50
System Service	1,201.75	1,097.81	(103.94)
General Plant	2,628.20	1,550.98	(1,077.22)
Total	**17,564.20**	**17,942.66**	**378.46**

System Access

Proposed System Access costs for the 2021 Test Year are ($1,021K) lower than the 2020 Bridge Year, due to a decrease in municipal road relocations of ($1,736K), a decrease in new commercial services of ($1,803K), and a decrease due the 2020 GPI Feeder Build of ($807K), partly offset by the Kalar TS Additional Switchgear project of $1,700K and the Niagara South Feeder project of $1,603K.

There were several customer-driven projects in 2020 that do not recur in 2021: KM3 Link = $877K and GPI Feeder Build = $807K.

In addition, municipal road relocation projects were higher than typical in 2020, due in part to several municipal projects to be completed prior to the Canada Summer Games, which are scheduled to be held in the Niagara Region in 2021.

Further details of NPEI's proposed 2021 Capital Projects and Programs are provided in the Distribution System Plan, which is included as Appendix 2-8 to this Exhibit.

System Renewal

Proposed System Renewal costs for the 2021 Test Year are $2,582K higher than the 2020 Bridge Year, mainly due to an increase in Overhead Rebuilds of $931K, an increase in Pole Replacements of $593K, an increase in Switchgear Replacements of

$295K, an increase in Subdivision Rehabilitation of $604K. In addition, NPEI is proposing to commence 2 new capital programs in 2021: Padmount Transformer Replacement $411K and Polemount Transformer Replacement $115K.

Further details of NPEI's proposed 2021 Capital Projects and Programs are provided in the Distribution System Plan, which is included as Appendix 2-8 to this Exhibit.

System Service

Proposed System Service costs for the 2021 Test Year are ($104K) lower than the 2020 Test Year, mainly due to the 2020 Greenlane Road at Ontario Tie Point project of $160K, which does not recur in 2021.

Further details of NPEI's proposed 2021 Capital Projects and Programs are provided in the Distribution System Plan, which is included as Appendix 2-8 to this Exhibit.

General Plant

Proposed General Plant for the 2021 Bridge Year is ($1,077K) lower than the 2020 Bridge Year, mainly due a decrease in Building of ($1,532K), due to the garage building being completed during 2020, partially offset by an increase in Vehicle costs of $356K.

Further details of NPEI's proposed General Plant for the 2021 Test Year are provided in Exhibit 2.1.2.

CAPITALIZATION POLICY

2.2.3 Capitalization Policy

The purpose of capitalizing expenditures is to provide an equitable allocation of costs among existing and future customers. As capital assets are expected to provide future economic benefits for more than one year, any expenditure incurred for the acquisition, construction, development or betterment of the capital assets should be capitalized. These capitalized costs are allocated over the estimated useful life of the assets by amortization.

All direct costs related to the construction of distribution system assets are capitalized. Direct labour includes Operations and Engineering actual time spent for the construction of distribution assets. Direct materials required for the construction of distribution assets that are issued from Inventory are capitalized. Any outside services or goods purchased directly for the construction of distribution assets are capitalized. Site restoration costs related to capital projects are also included as capitalized costs. Fleet utilization of NPEI owned vehicles and equipment are capitalized using standard per hour rates. NPEI reviews its vehicle and equipment utilization rates on an annual basis. The vehicle and equipment utilization rates do not include a component related to depreciation. Fleet and equipment used on a capital project are recorded by the operation's and engineering departments on the daily timesheets. Labour overhead burdens are recorded as part of each weekly payroll. Actual benefit expenditures are captured on a monthly basis. Any difference between the labour overhead burden recorded through payroll and the actual expenses is adjusted on a monthly basis. NPEI does not capitalize any Salaried employees labour and benefit costs.

NPEI has included its Capitalization Policy as Appendix 2-5 to this Exhibit.

There have been no changes to NPEI's Capitalization Policy since NPEI's last Cost-of-Service Rate Application (EB-2014-0096).

CAPITALIZATION OF OVERHEAD

2.2.4 Capitalization of Overhead

The portion of OM&A expenses capitalized by NPEI are: 1) employee benefit costs, which includes statutory payroll costs (EI, CPP, WSIB, EHT), statutory holidays, vacation, sick and rest time, life insurance, health and dental benefits and pension costs and 2) fleet expenses.

Under IFRS, the benefit costs allocated to capital labour are capitalized, since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management.

The fleet expenses include the labour and benefits costs of fleet department and the costs of goods and services purchased to maintain and operate NPEI's fleet. These costs are accumulated in OM&A. Equipment utilization is recorded weekly from the operations and engineering timesheets. Each vehicle or piece of equipment has a standard rate per hour assigned to it by vehicle group. For example, small vehicles all have a usage rate of $10.50 per hour. Equipment used for capital projects are capitalized and equipment used for maintenance are recorded as OM&A expenses. These costs are directly attributable to bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management.

<u>Labour Burden</u>

Section 2.2.2.6 of the Filing Requirements state: "*The applicant must identify the burden rates related to the capitalization of costs of self-constructed assets. Furthermore, if the burden rates were changed since the last rebasing application, the applicant must identify the burden rates prior to and after the change.*"

NPEI's actual burden rate has ranged between 60% and 65% for the period from 2015 to 2019. The burden rate is adjusted periodically based on the actual benefit and labour dollars. For the 2020 Bridge Year and 2021 Test Year the burden rate for all labour is estimated at 64%.

The range of burden rates was from 58% to 60% in NPEI's 2015 Cost of Service Rate Application (EB-2014-0096). Refer to Exhibit 4, Tab 4 Schedule 4 for details regarding NPEI's employee benefits.

NPEI has completed the OEB's Appendix 2-D, which is included as Appendix 2-6 to this Exhibit.

COSTS OF ELIGIBLE INVESTMENTS FOR DISTRIBUTORS

2.2.5 Costs of Eligible Investments for Distributors

Section 2.2.2.7 of the Filing Requirements state: "*For any costs incurred to make investments that are eligible for rate protection as described in Section 79.1 of the Ontario Energy Board Act, 1998 (OEB Act) and O.Reg. 330/09 under the OEB Act, including any facilities forecast to enter into service beyond the test year, the distributor may seek approval to recover the rate protection component of the costs.*"

"For distributors that are already receiving rate protection as a result of a previous application and approval (in many cases, based on a forecast of capital expenditures on qualifying connection assets), the new (current) cost of service application should include an update to include the actual costs incurred for the investments as well as a depreciation adjustment to calculate a new capital amount for the input into Appendices 2-FA through 2-FC."

NPEI is not seeking approval for any qualifying investments, nor has NPEI requested such approval in any previous rate application.

NEW POLICY OPTIONS FOR THE FUNDING OF CAPITAL

2.2.6 New Policy Options for the Funding of Capital

On September 18, 2014, the OEB issued the *Report of the Board on New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (the ACM Report). The ACM reflects an evolution of the Incremental Capital Module (ICM) adopted by the OEB in 2008.

As part of a cost of service application, a distributor may propose qualifying ACM capital projects that are expected to come into service during the subsequent Price Cap IR term.

NPEI is not requesting ACM treatment for any future capital projects in this Application.

ADDITION OF ACM AND ICM ASSETS TO RATE BASE

2.2.7 Addition of ACM and ICM Assets to Rate Base

Section 2.2.2.4 of the Filing Requirements state: "*Any distributor that has an approved ACM or ICM from a previous Price Cap IR application must file a schedule of the ACM/ICM capital assets (i.e. PP&E and associated depreciation) it proposes to incorporate into rate base.*"

NPEI has not previously requested ICM or ACM treatment for any capital assets.

SERVICE QUALITY AND RELIABILITY PERFORMANCE

2.2.8 Service Quality and Reliability Performance

Chapter 7 of the OEB's *Distribution System Code* outlines the OEB's expectations regarding Service Quality Requirements for Electricity Distributors. Table 2.2.8.1 below provides NPEI's Service Quality Indicators for the 2015-2019 historical years:

Table 2.2.8.1 – Historical Service Quality Indicators

Indicator	OEB Minimum Standard	2015	2016	2017	2018	2019
Low Voltage Connections	90%	91.4%	92.7%	91.5%	93.3%	93.6%
High Voltage Connections	90%	94.5%	100.0%	100.0%	90.7%	100.0%
Telephone Accessibility	65%	82.7%	83.0%	88.0%	85.9%	84.7%
Appointments Met	90%	95.7%	99.8%	98.3%	98.9%	99.5%
Written Response to Enquiries	80%	100.0%	100.0%	93.1%	86.3%	88.9%
Emergency Urban Response	80%	91.5%	97.1%	97.1%	100.0%	97.7%
Emergency Rural Response	80%	83.7%	93.5%	100.0%	100.0%	94.3%
Telephone Call Abandon Rate	10%	1.0%	0.9%	0.9%	1.3%	0.9%
Appointments Scheduling	90%	100.0%	100.0%	100.0%	100.0%	100.0%
Rescheduling a Missed Appointment	100%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85%	100.0%	100.0%	100.0%	100.0%	100.0%

NPEI confirms that the data presented in table 2.2.8.1 above for 2015-2018 is consistent with the indicators that have been reported on NPEI's annual *Scorecard of Electricity Distributors* each year. The data for 2019 presented in the table above will be reported on NPEI's 2019 *Scorecard of Electricity Distributors* in September 2020.

For each Service Quality Indicator above, NPEI's performance meets or exceeds the OEB's minimum standard.

The OEB's *Electricity Reporting and Record Keeping Requirements* ("RRR"), Section 2.1.4.2, requires electricity distributors to report, on an annual basis, the following System Reliability Indicators:

System Average Interruption Duration Index (SAIDI)

$$SAIDI = \frac{Total\ Customer\ Hours\ of\ Interruptions}{Average\ Number\ of\ Customers\ Served}$$

System Average Interruption Frequency Index (SAIFI)

$$SAIFI = \frac{Total\ Customer\ Interruptions}{Average\ Number\ of\ Customers\ Served}$$

Customer interruptions are reported by Cause Code, as set out in Section 2.1.4.2.5 of the RRR. The SAIDI and SAIFI indices that are reported on the annual *Scorecards of Electricity Distributors* exclude customer interruptions that are due to Loss of Supply and Major Events.

Table 2.2.8.2 below shows NPEI's System Reliability Indicators for the 2015-2019 historical years. NPEI confirms that the data presented in Table 2.2.8.2 is consistent with data that has been reported, or will be reported, on NPEI's annual *Scorecard of Electricity Distributors.*

Table 2.2.8.2 – Historical System Reliability Indicators

Reliability Indicator	Target	2015	2016	2017	2018	2019	5 Year Average
SAIDI - including loss of supply		2.31	1.68	1.51	2.35	2.43	2.06
SAIFI - including loss of supply		1.70	1.41	1.69	1.98	1.83	1.72
SAIDI - excluding loss of supply		2.05	1.52	1.37	1.98	2.03	1.79
SAIFI - excluding loss of supply		1.42	1.38	1.55	1.65	1.63	1.52
SAIDI - excluding loss of supply & major events	2.58	2.05	1.52	1.37	1.98	2.03	1.79
SAIFI - excluding loss of supply & major events	1.30	1.42	1.38	1.55	1.65	1.63	1.52

As can be seen from Table 2.2.8.2 above, NPEI has not reported any Major Event outages during the 2015 – 2019 historical years.

Section 2.1.4.2 of the RRR defines a Major Event as follows:

"'Major Event' is defined as an event that is beyond the control of the distributor and is:
a) unforeseeable;
b) unpredictable;
c) unpreventable; or
d) unavoidable.
Such events disrupt normal business operations and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, they take significantly longer than usual to repair, and they affect a substantial number of customers."

During recent years, NPEI has typically experienced 1 or 2 weather-related events each year, which have had a significant impact on reliability. Here, NPEI has defined significant to mean impacting 10% of customers (i.e. approximately 5,600 customers currently), or resulting in an equivalent number of customer hours of interruption (i.e. approximately 5,600 customer hours).

In NPEI's view, these typical weather-related events do not meet the definition of a Major Event, since they do not *"occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system".* However, NPEI tracks these events internally, and typically includes them in NPEI's Management Discussion and Analysis for the annual *Scorecard of Electricity Distributors.*

During the past 5 historical years, NPEI has identified 7 such weather-related events which have either impacted 10% of customers or caused an equivalent number of customer hours of interruption.

Table 2.2.8.3 – Significant Weather-Related Events

Date	Description	# of Customer Interuptions	# of Customer Hour Interruptions	Average # of Customers	Contribution to Annual SAIDI	Contribution to Annual SAIFI
March 2-3, 2015	Freezing Rain	3,987	9,842	53,002	0.19	0.08
June 20, 2016	Lightning	5,415	9,416	53,671	0.18	0.10
March 8, 2017	Wind Storm	8,255	7,426	55,013	0.13	0.15
April 4, 2018	Wind Storm	11,052	11,769	55,811	0.21	0.20
May 4, 2018	Wind Storm	9,767	11,733	55,811	0.21	0.18
Feb 24-25, 2019	Wind Storm	10,454	4,108	56,025	0.07	0.19
Dec 1-2, 2019	Freezing Rain	12,885	33,199	56,025	0.59	0.23

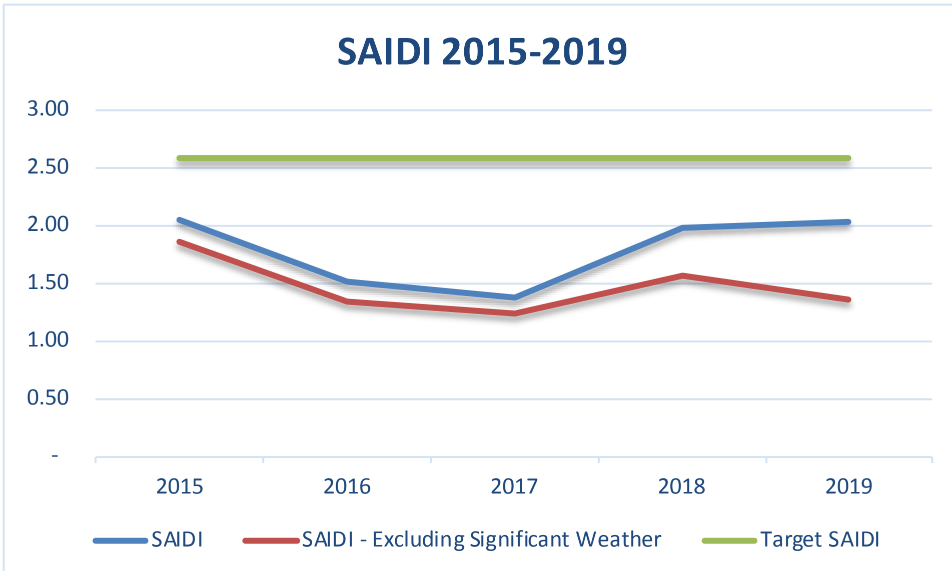
Table 2.2.8.4 below shows NPEI's System Reliability Indicators, restated to exclude the impact of the 7 weather-related events identified in Table 2.2.8.3 above.

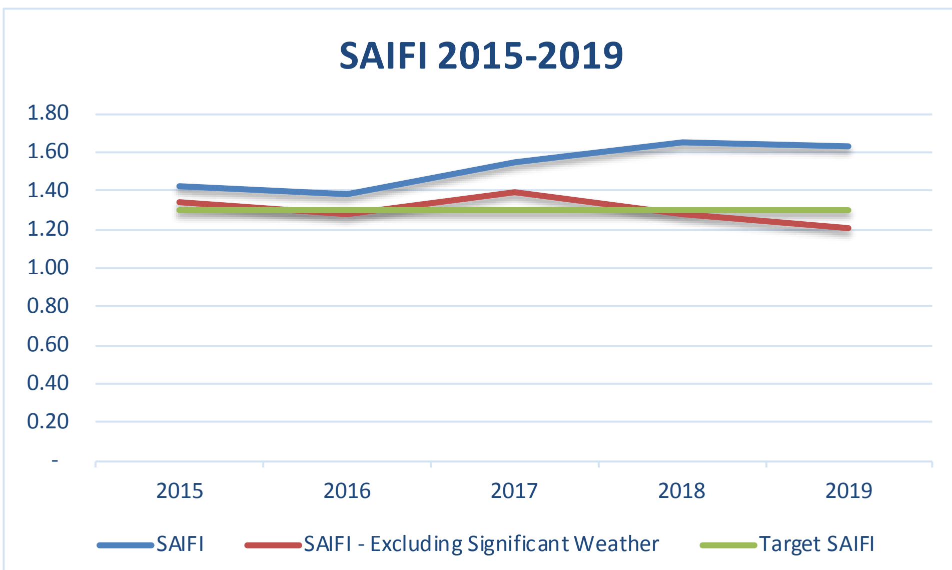
Table 2.2.8.4– Historical System Reliability Indicators (Excluding Significant Weather Related Events)

SQI (Excluding Significant Weather-Related Events)	2015	2016	2017	2018	2019
SAIDI - excluding loss of supply & significant weather events	1.86	1.34	1.23	1.56	1.36
SAIFI - excluding loss of supply & significant weather events	1.34	1.28	1.40	1.28	1.21

The data included in Table 2.2.2.8.2 and Table 2.2.2.8.4 is presented in the charts below.

Table 2.2.8.5 – Historical SAIDI and SAIFI Charts





The charts above indicate that both SAIDI and SAIFI have been trending relatively consistently over the historical period.

Further details of NPEI's system reliability indicators are provided in NPEI's Distribution System Plan (Section 5.2.3.1.3 and Appendix C).

Exhibit 2: Rate Base

Tab 3 (of 3): Distribution System Plan

DISTRIBUTION SYSTEM PLAN

2.3.1 Distribution System Plan

Niagara Peninsula Energy Inc. ("NPEI") is an Electrical Distribution Company servicing an area of approximately 820 square kilometers. NPEI's service area is composed of Niagara Falls, Lincoln, West Lincoln and the Village of Fonthill and its system contains a mix of urban and rural electrical distribution. Niagara Peninsula Energy's Mission is to deliver safe, efficient, and reliable electricity. Niagara Peninsula Energy employees provide the best possible service to all Customers, delivering environmentally responsible and sustainable energy for the future viability of our Communities.

In order to maintain the sustainability of its operations, sufficient funding to facilitate planning, equipment, personnel and systems must be in place to provide the core functions required. Establishing a sound and viable long-term plan for personnel recruitment and training, equipment procurement, software and technology tools to aid in asset management, design and modeling, communication systems, billing and accounting systems, are key to ensuring that these services are provided in an efficient and economical manner.

To demonstrate commitment to the efficient and economical provision of these services and to comply with the requirements of OEB’s Chapter 5 Consolidated Distribution System Plan Filing Requirements, NPEI has developed this Distribution System Plan ("DSP"). An Asset Condition Assessment ("ACA"), developed by Kinectrics Inc., provides the basis for system renewal investments, the largest portion of NPEI’s capital expenditures. The ACA was developed using data originating from regular programs established by NPEI, including sub-station maintenance and testing, pole testing, pad-mounted equipment inspections, kiosk inspections, manhole inspections, and sidewalk vault inspections. These inspection, testing, and maintenance programs are carried out by qualified contractors following criteria provided by NPEI to determine asset condition, public safety concerns, access issues, and to estimate remaining asset life. Digital images are obtained and the information is linked to the asset within the Geographic Information System (GIS), from which reports can be generated relating to quantities, age, type, condition and other relevant criteria. These reports are compiled to generate data required as input for the ACA. The Health Indices and flagged for actions strategies determined from the ACA provides data critical for long term planning and the development of the 2021 to 2025 Capital Plan as outlined in this DSP.

Understanding and responding to the preferences of NPEI's customers has been and continues to be the focus of NPEI's efforts in developing short and long-term plans. NPEI's customer base consists of residential, small and midsized business customers. Among competing outcomes, price, reliability and finding internal cost efficiencies are the top three priorities for both residential and small business customers. With respect to reliability, reducing the overall number of outages, the overall length of outages and improving restoration time are the top three priorities for both rate classes. While keeping price at a reasonable and affordable level is an important priority for customers, the majority feel that investing in the grid to maintain reliability if preferable to deferring investments to keep bills low.

Overall, NPEI's customers were supportive of its 2021-2025 draft plan as it was presented during the customer engagement process. In each of the three workbooks (Residential, Small Business and GS > 50 kW), the majority of customers surveyed indicated a preference for NPEI to either maintain the proposed rate increase to deliver a program that focuses on the priorities of its draft plan, or to improve service even if that means an increase that exceeds what is proposed in the draft plan.

In each case, however, the customer support for maintaining the proposed level of rate increase was greater than the customer support for improving service even if that means an increase that exceeds what is proposed in the draft plan.

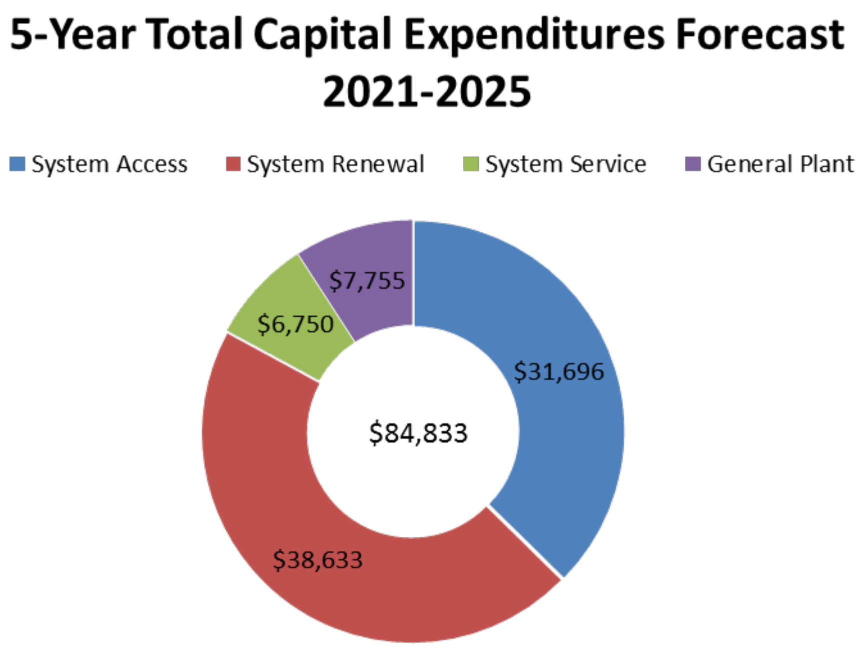
Further, among Vulnerable Residential customers, a minority (29%) indicated that NPEI should keep increases below what is proposed in the draft plan even if that means reductions in service, compared to 11% of Residential customers overall.

In determining whether to adjust the overall level of spending proposed in its draft plan, NPEI has considered the following factors:

- Balancing customer preferences in general against the preferences expressed by the more vulnerable Residential customers.
- The resulting level of bill impacts to all customer classes.
- Internal resource constraints: whether or not an increase in the overall level of proposed capital projects or programs may require additional engineering or operations resources beyond NPEI's current staffing levels.
- Financial leverage: whether or not an increase in the overall level of proposed capital projects or programs may require NPEI to incur additional debt.

Based on the above considerations, NPEI has decided to maintain the overall proposed level of capital spending consistent with what was included in the draft plan.

NPEI considers all customer feedback and preferences in determining the pacing of its investments and in optimal selection of projects. Survey results were used to inform the asset management plan and development of the capital investment plan. In addition to the customer feedback, the corporate strategic priorities and asset management objectives form the high-level framework for NPEI's investment programs. Asset management objectives identify investments that are best aligned from an overall benefit and risk management perspective. An integral part of achieving the asset management objectives are inspection, maintenance and replacement programs, to ensure system performance is sustained during the entire asset service life. To align to asset management best practices and to provide consistency with its Strategic Priorities, NPEI has adopted an asset management strategy that provides direction for the management of assets while recognizing realistic service and performance goals. The asset management strategy ensures a continual and consistent focus on delivering services in a way that balances risk and long term costs. The combination of NPEI's asset management and capital expenditure planning process leads to a capital expenditure plan consisting of a five-year capital expenditure forecast. The asset management and capital investment process identify System Access, System Renewal, System Service and General Plant requirements. These requirements result in a list of mandatory and added value investments to be executed over the investment period. The final investment portfolio considers the balance between achieving NPEI's Asset Management Objectives and the impact on customer rates. NPEI plans to invest an average of $17M in capital expenditures per year across all four investment categories for a gross total of approximately $84.8M. The figure below shows the 5-year expenditures forecast by investment category.



Expenditures in the System Access category are driven by external requirements such as servicing new customer load and relocating distribution plant to suit road authorities. These expenditures are mandatory. Specific projects such as accommodating the new Niagara South Hospital development, which is planned as multiyear projects, are budgeted for based on NPEI's estimates, in conjunction with information from external agencies. NPEI plans to invest an average of $5.68M in capital expenditures per year within the System Access category which accounts for 33.5% of the gross total over the forecast period.

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and play a crucial role in the overall reliability, safety and sustainment of the distribution system. The majority of projects found under the System Renewal framework are overhead rebuild projects which are planned for based on the condition of NPEI's in-service assets. Other programs within the System Renewal category consist of replacing individual assets such as poles, transformers and switchgear that are deemed to be at end of life due to a poor or very poor rating in the asset condition assessment. Over the DSP period, 100 poles, 73 transformers and 4 switchgears per year are planned for replacement over and above those included in the overhead rebuild projects. NPEI had strong customer support for these programs and in some cases, customers were willing to pay more to accelerate the program. Another major program planned within the forecast period is Direct Buried Subdivision Rehabilitation. The program includes installation of duct in the older subdivisions where the primary and secondary conductors were installed by direct burial. These cables are nearing end of life and will require replacement in the near future. The duct installed as part of this program will facilitate the replacement of these underground conductors. NPEI plans to invest an average of $8.05M in capital expenditures per year within the System Renewal category which accounts for 47.4% of the gross total over the forecast period.

Expenditures in the System Service category are driven by the need to ensure that the distribution system continues to meet operational objectives (such as reliability, grid flexibility and DER integration) while addressing anticipated future customer electricity service requirements. Expenditures in this category can include the installation of automated reclosers and switches, line sensors and fault indicators or conversion from overhead to underground networks to cost effectively improve system reliability and efficiency. NPEI plans to invest an average of $1.69 in capital expenditures per year within the System Service category which accounts for 9.96% of the gross total over the forecast period.

Expenditures in the General Plant category are driven by the need to modify, replace or purchase assets that are not part of the distribution system but support the utility's everyday operations. The significant program found under the General Plant framework is the Information Systems and Technology program. Expenditures in this program are driven by the need to acquire, enhance and upgrade computer hardware and software used in information technology (IT) and operation technology (OT) applications. These hardware and software tools are crucial to the day-to-day running of the organization and must be protected and secured to reduce the likelihood of cyber security breaches. In addition to maintaining the IT and OT systems, another significant driver of General Plan spending is the renewal of the operations fleet equipment. NPEI plans to invest an average of $1.55M in capital expenditures per year within the General Plant category which accounts for 9.14% of the gross total over the forecast period.

The DSP's purpose is to show how NPEI plans, manages and develops the electrical distribution system and associated infrastructure. It outlines the long term Capital Expenditure Plan to meet needs stemming from internal drivers, external drivers and strategic investments, while maintaining a reasonable impact on customers' rates and system performance.

NPEI's DSP is included as Appendix 2-8 to this Exhibit.

Appendix 2-1

OEB Appendix 2-BA

File Number: EB-2020-0040
Exhibit: 2
Tab:
Schedule:
Page:

Date: 8/31/2020

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard: MIFRS
Year: 2015

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 3,229,308	$ 183,006		$ 3,412,314	-$ 2,858,895	-$ 199,344		-$ 3,058,240	$ 354,075
CEC	1612	Land Rights (Formally known as Account 1906)	$ 1,604,397			$ 1,604,397	-$ 925,261	-$ 57,099		-$ 982,360	$ 622,037
N/A	1805	Land	$ 507,273			$ 507,273				$ -	$ 507,273
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,638	$ -		-$ 111,638	$ -
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 6,651,423	$ 1,380		$ 6,652,803	-$ 1,553,199	-$ 161,714		-$ 1,714,912	$ 4,937,891
47	1820	Distribution Station Equipment <50 kV	$ 6,867,626			$ 6,867,626	-$ 3,060,144	-$ 143,014		-$ 3,203,158	$ 3,664,468
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 45,208,940	$ 2,144,405		$ 47,353,345	-$ 25,075,924	-$ 490,601		-$ 25,566,525	$ 21,786,821
47	1835	Overhead Conductors & Devices	$ 30,044,277	$ 2,068,453		$ 32,112,730	-$ 10,922,656	-$ 599,142		-$ 11,521,798	$ 20,590,932
47	1840	Underground Conduit	$ 10,359,258	$ 781,297		$ 11,140,555	-$ 2,533,445	-$ 188,876		-$ 2,722,321	$ 8,418,234
47	1845	Underground Conductors & Devices	$ 68,835,405	$ 4,768,414		$ 73,603,819	-$ 40,281,085	-$ 1,336,392		-$ 41,617,477	$ 31,986,342
47	1850	Line Transformers	$ 38,491,416	$ 2,318,687	-$ 191,528	$ 40,618,575	-$ 22,218,278	-$ 774,287	$ 191,528	-$ 22,801,037	$ 17,817,538
47	1855	Services (Overhead & Underground)	$ 6,275,832	$ 1,006,637		$ 7,282,469	-$ 1,545,082	-$ 271,165		-$ 1,816,247	$ 5,466,222
47	1860	Meters	$ 3,339,303	$ 184,577		$ 3,523,881	-$ 1,203,525	-$ 201,532		-$ 1,405,057	$ 2,118,824
47	1860	Meters (Smart Meters)	$ 6,201,235	$ 144,015		$ 6,345,251	-$ 1,445,169	-$ 419,688		-$ 1,864,857	$ 4,480,393
47	1875	Street Lighting and Signal Systems	$ 21,835			$ 21,835	-$ 8,020	-$ 873		-$ 8,893	$ 12,942
N/A	1905	Land	$ 508,970			$ 508,970				$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 16,730,503	$ 468,660		$ 17,199,163	-$ 2,949,145	-$ 286,696		-$ 3,235,841	$ 13,963,322
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252	$ -		-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,670,224	$ 25,554		$ 1,695,778	-$ 1,033,664	-$ 105,025		-$ 1,138,689	$ 557,089
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 320,323			-$ 320,323	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,479,012	$ 248,789		$ 2,727,801	-$ 1,686,626	-$ 285,181		-$ 1,971,807	$ 755,994
10	1930	Transportation Equipment	$ 8,790,946	$ 490,775	-$ 503,538	$ 8,778,183	-$ 4,406,002	-$ 437,229	$ 503,538	-$ 4,339,694	$ 4,438,489
8	1935	Stores Equipment	$ 268,478	$ 54,801		$ 323,279	-$ 208,561	-$ 11,078		-$ 219,640	$ 103,639
8	1940	Tools, Shop & Garage Equipment	$ 2,015,322	$ 66,619		$ 2,081,941	-$ 1,611,239	-$ 80,243		-$ 1,691,482	$ 390,460
8	1945	Measurement & Testing Equipment	$ 204,006			$ 204,006	-$ 199,219	-$ 3,239		-$ 202,459	$ 1,548
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment	$ 1,075,266	$ 65,663		$ 1,140,929	-$ 211,989	-$ 47,026		-$ 259,016	$ 881,913
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951			$ 72,951	-$ 72,702	-$ 249		-$ 72,951	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961	$ -		-$ 128,961	$ -
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 22,390,322	-$ 5,664,428		-$ 28,054,750	$ 6,850,144	$ 613,263		$ 7,463,406	-$ 20,591,344
						$ -				$ -	$ -
		Sub-Total	**$ 241,001,828**	**$ 9,357,304**	**-$ 695,065**	**$ 249,664,067**	**-$ 121,098,631**	**-$ 5,486,431**	**$ 695,066**	**-$ 125,889,996**	**$ 123,774,071**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 241,001,828**	**$ 9,357,304**	**-$ 695,065**	**$ 249,664,067**	**-$ 121,098,631**	**-$ 5,486,431**	**$ 695,066**	**-$ 125,889,996**	**$ 123,774,071**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 5,486,431**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 5,486,431

Accounting Standard	MIFRS
Year	2016

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 3,412,314	$ 342,477		$ 3,754,791	-$ 3,058,240	-$ 230,226		-$ 3,288,465	$ 466,326
CEC	1612	Land Rights (Formally known as Account 1906)	$ 1,604,397			$ 1,604,397	-$ 982,360	-$ 57,099		-$ 1,039,459	$ 564,938
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,638	$ -		-$ 111,638	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 6,652,803			$ 6,652,803	-$ 1,714,912	-$ 162,636		-$ 1,877,549	$ 4,775,255
47	1820	Distribution Station Equipment <50 kV	$ 6,867,626			$ 6,867,626	-$ 3,203,158	-$ 143,014		-$ 3,346,172	$ 3,521,454
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 47,353,345	$ 2,661,776		$ 50,015,121	-$ 25,566,525	-$ 538,489		-$ 26,105,014	$ 23,910,107
47	1835	Overhead Conductors & Devices	$ 32,112,730	$ 2,462,572		$ 34,575,301	-$ 11,521,798	-$ 617,037		-$ 12,138,835	$ 22,436,467
47	1840	Underground Conduit	$ 11,140,555	$ 1,197,894		$ 12,338,449	-$ 2,722,321	-$ 208,667		-$ 2,930,988	$ 9,407,461
47	1845	Underground Conductors & Devices	$ 73,603,819	$ 3,808,930		$ 77,412,749	-$ 41,617,477	-$ 1,451,211		-$ 43,068,687	$ 34,344,061
47	1850	Line Transformers	$ 40,618,575	$ 1,710,386	-$ 202,611	$ 42,126,350	-$ 22,801,037	-$ 837,062	$ 202,611	-$ 23,435,488	$ 18,690,862
47	1855	Services (Overhead & Underground)	$ 7,282,469	$ 1,182,855		$ 8,465,324	-$ 1,816,247	-$ 314,955		-$ 2,131,202	$ 6,334,122
47	1860	Meters	$ 3,523,881	$ 557,578	-$ 32,045	$ 4,049,414	-$ 1,405,057	-$ 215,222	$ 24,610	-$ 1,595,669	$ 2,453,745
47	1860	Meters (Smart Meters)	$ 6,345,251	-$ 35,971		$ 6,309,279	-$ 1,864,857	-$ 429,776		-$ 2,294,633	$ 4,014,646
47	1875	Street Lighting and Signal Systems	$ 21,835			$ 21,835	-$ 8,893	-$ 873		-$ 9,766	$ 12,069
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 17,199,163	$ 52,753		$ 17,251,916	-$ 3,235,841	-$ 291,200		-$ 3,527,041	$ 13,724,875
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252	$ -		-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,695,778	$ 28,031		$ 1,723,808	-$ 1,138,689	-$ 100,718		-$ 1,239,407	$ 484,401
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 320,323			-$ 320,323	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,727,801	$ 241,217		$ 2,969,018	-$ 1,971,807	-$ 288,960		-$ 2,260,767	$ 708,251
10	1930	Transportation Equipment	$ 8,778,183	$ 792,445	-$ 496,427	$ 9,074,202	-$ 4,339,694	-$ 429,572	$ 496,427	-$ 4,272,839	$ 4,801,363
8	1935	Stores Equipment	$ 323,279			$ 323,279	-$ 219,640	-$ 14,111		-$ 233,750	$ 89,529
8	1940	Tools, Shop & Garage Equipment	$ 2,081,941	$ 121,500	-$ 2,778	$ 2,200,663	-$ 1,691,482	-$ 73,244	$ 1,829	-$ 1,762,896	$ 437,767
8	1945	Measurement & Testing Equipment	$ 204,006			$ 204,006	-$ 202,459	-$ 1,110		-$ 203,569	$ 438
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 1,140,929	$ 301,990		$ 1,442,919	-$ 259,016	-$ 57,205		-$ 316,221	$ 1,126,697
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951			$ 72,951	-$ 72,951	$ -		-$ 72,951	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961	$ -		-$ 128,961	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 28,054,750	-$ 4,031,451		-$ 32,086,201	$ 7,463,406	$ 738,438		$ 8,201,844	-$ 23,884,357
						$ -	$ -			$ -	$ -
		Sub-Total	**$ 249,664,067**	**$ 11,394,981**	**-$ 733,861**	**$ 260,325,187**	**-$ 125,889,996**	**-$ 5,723,947**	**$ 725,476**	**-$ 130,888,467**	**$ 129,436,720**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 249,664,067**	**$ 11,394,981**	**-$ 733,861**	**$ 260,325,187**	**-$ 125,889,996**	**-$ 5,723,947**	**$ 725,476**	**-$ 130,888,467**	**$ 129,436,720**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 5,723,947**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 5,723,947

Accounting Standard MIFRS
Year 2017

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 3,754,791	$ 710,896		$ 4,465,687	-$ 3,288,465	-$ 299,692		-$ 3,588,157	$ 877,530
CEC	1612	Land Rights (Formally known as Account 1906)	$ 1,604,397			$ 1,604,397	-$ 1,039,459	-$ 57,099		-$ 1,096,558	$ 507,839
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,638	$ -		-$ 111,638	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 6,652,803	$ 56,952		$ 6,709,756	-$ 1,877,549	-$ 164,060		-$ 2,041,609	$ 4,668,147
47	1820	Distribution Station Equipment <50 kV	$ 6,867,626	$ 237,780		$ 7,105,405	-$ 3,346,172	-$ 145,656		-$ 3,491,827	$ 3,613,578
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 50,015,121	$ 2,255,688	-$ 89,272	$ 52,181,537	-$ 26,105,014	-$ 587,413	$ 53,099	-$ 26,639,328	$ 25,542,210
47	1835	Overhead Conductors & Devices	$ 34,575,301	$ 2,148,697	-$ 29,733	$ 36,694,265	-$ 12,138,835	-$ 643,863	$ 14,866	-$ 12,767,832	$ 23,926,434
47	1840	Underground Conduit	$ 12,338,449	$ 875,650		$ 13,214,099	-$ 2,930,988	-$ 229,403		-$ 3,160,391	$ 10,053,708
47	1845	Underground Conductors & Devices	$ 77,412,749	$ 2,817,639		$ 80,230,387	-$ 43,068,687	-$ 1,538,514		-$ 44,607,201	$ 35,623,186
47	1850	Line Transformers	$ 42,126,350	$ 1,904,620	-$ 392,980	$ 43,637,990	-$ 23,435,488	-$ 893,252	$ 331,284	-$ 23,997,455	$ 19,640,534
47	1855	Services (Overhead & Underground)	$ 8,465,324	$ 1,340,226	-$ 11,588	$ 9,793,963	-$ 2,131,202	-$ 365,417	$ 5,794	-$ 2,490,825	$ 7,303,138
47	1860	Meters	$ 4,049,414	$ 589,721	-$ 172,476	$ 4,466,658	-$ 1,595,669	-$ 246,292	$ 70,228	-$ 1,771,733	$ 2,694,926
47	1860	Meters (Smart Meters)	$ 6,309,279	$ 349,555	$ 440	$ 6,659,274	-$ 2,294,633	-$ 435,062		-$ 2,729,695	$ 3,929,579
47	1875	Street Lighting and Signal Systems	$ 21,835			$ 21,835	-$ 9,766	-$ 873		-$ 10,640	$ 11,195
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 17,251,916	$ 403,007		$ 17,654,923	-$ 3,527,041	-$ 295,156		-$ 3,822,196	$ 13,832,726
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252	$ -		-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,723,808	$ 23,457	-$ 5,395	$ 1,741,871	-$ 1,239,407	-$ 96,266	$ 3,821	-$ 1,331,852	$ 410,019
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 320,323			-$ 320,323	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,969,018	$ 332,121		$ 3,301,140	-$ 2,260,767	-$ 309,625		-$ 2,570,392	$ 730,747
10	1930	Transportation Equipment	$ 9,074,202	$ 876,513	-$ 284,325	$ 9,666,390	-$ 4,272,839	-$ 476,593	$ 284,325	-$ 4,465,107	$ 5,201,283
8	1935	Stores Equipment	$ 323,279			$ 323,279	-$ 233,750	-$ 14,111		-$ 247,861	$ 75,418
8	1940	Tools, Shop & Garage Equipment	$ 2,200,663	$ 92,559	-$ 3,544	$ 2,289,678	-$ 1,762,896	-$ 79,353	$ 1,093	-$ 1,841,156	$ 448,522
8	1945	Measurement & Testing Equipment	$ 204,006			$ 204,006	-$ 203,569	$ -		-$ 203,569	$ 438
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 1,442,919	-$ 82,064		$ 1,360,855	-$ 316,221	-$ 59,588		-$ 375,810	$ 985,045
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951			$ 72,951	-$ 72,951	$ -		-$ 72,951	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961	$ -		-$ 128,961	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 32,086,201	-$ 2,471,484		-$ 34,557,685	$ 8,201,844	$ 824,191		$ 9,026,035	-$ 25,531,650
						$ -	$ -			$ -	$ -
		Sub-Total	**$ 260,325,187**	**$ 12,461,533**	**-$ 988,873**	**$ 271,797,847**	**-$ 130,888,467**	**-$ 6,113,096**	**$ 764,510**	**-$ 136,237,053**	**$ 135,560,794**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 260,325,187**	**$ 12,461,533**	**-$ 988,873**	**$ 271,797,847**	**-$ 130,888,467**	**-$ 6,113,096**	**$ 764,510**	**-$ 136,237,053**	**$ 135,560,794**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 6,113,096**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 6,113,096

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CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 4,465,687	$ 288,891		$ 4,754,578	-$ 3,588,157	-$ 427,955		-$ 4,016,112	$ 738,466
CEC	1612	Land Rights (Formally known as Account 1906)	$ 1,604,397			$ 1,604,397	-$ 1,096,558	-$ 57,099		-$ 1,153,657	$ 450,740
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,638			-$ 111,638	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 6,709,756	$ 135,288		$ 6,845,044	-$ 2,041,609	-$ 167,567		-$ 2,209,176	$ 4,635,868
47	1820	Distribution Station Equipment <50 kV	$ 7,105,405	$ 14,521	-$ 150,005	$ 6,969,921	-$ 3,491,827	-$ 143,386	$ 150,005	-$ 3,485,208	$ 3,484,713
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 52,181,537	$ 2,347,020	-$ 362,659	$ 54,165,898	-$ 26,639,328	-$ 631,854	$ 326,088	-$ 26,945,094	$ 27,220,805
47	1835	Overhead Conductors & Devices	$ 36,694,265	$ 2,350,169		$ 39,044,434	-$ 12,767,832	-$ 674,418		-$ 13,442,250	$ 25,602,184
47	1840	Underground Conduit	$ 13,214,099	$ 1,056,468		$ 14,270,567	-$ 3,160,391	-$ 248,724		-$ 3,409,115	$ 10,861,452
47	1845	Underground Conductors & Devices	$ 80,230,387	$ 2,212,265		$ 82,442,652	-$ 44,607,201	-$ 1,596,693		-$ 46,203,895	$ 36,238,758
47	1850	Line Transformers	$ 43,637,990	$ 2,042,986	-$ 246,129	$ 45,434,847	-$ 23,997,455	-$ 950,899	$ 246,129	-$ 24,702,226	$ 20,732,621
47	1855	Services (Overhead & Underground)	$ 9,793,963	$ 1,316,978		$ 11,110,940	-$ 2,490,825	-$ 418,078		-$ 2,908,903	$ 8,202,037
47	1860	Meters	$ 4,466,658	$ 634,043	$ 422,526	$ 5,523,228	-$ 1,771,733	-$ 280,774	$ 99,854	-$ 1,952,653	$ 3,570,575
47	1860	Meters (Smart Meters)	$ 6,659,274	$ 421,437	-$ 573,998	$ 6,506,713	-$ 2,729,695	-$ 442,004	$ 4,287	-$ 3,167,412	$ 3,339,301
47	1875	Street Lighting and Signal Systems	$ 21,835			$ 21,835	-$ 10,640	-$ 873		-$ 11,513	$ 10,322
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 17,654,923	$ 1,024,864		$ 18,679,787	-$ 3,822,196	-$ 310,101		-$ 4,132,298	$ 14,547,490
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,741,871	$ 115,088		$ 1,856,959	-$ 1,331,852	-$ 96,694		-$ 1,428,546	$ 428,413
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 320,323			-$ 320,323	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 3,301,140	$ 326,559	-$ 3,048	$ 3,624,650	-$ 2,570,392	-$ 300,817	$ 3,048	-$ 2,868,161	$ 756,489
10	1930	Transportation Equipment	$ 9,666,390	$ 518,258	-$ 422,515	$ 9,762,133	-$ 4,465,107	-$ 543,224	$ 405,174	-$ 4,603,157	$ 5,158,976
8	1935	Stores Equipment	$ 323,279	$ 5,215		$ 328,494	-$ 247,861	-$ 14,322		-$ 262,183	$ 66,311
8	1940	Tools, Shop & Garage Equipment	$ 2,289,678	$ 66,032		$ 2,355,710	-$ 1,841,156	-$ 81,857		-$ 1,923,013	$ 432,697
8	1945	Measurement & Testing Equipment	$ 204,006			$ 204,006	-$ 203,569			-$ 203,569	$ 438
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 1,360,855	$ 109,826		$ 1,470,680	-$ 375,810	-$ 62,399		-$ 438,208	$ 1,032,472
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951			$ 72,951	-$ 72,951			-$ 72,951	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 34,557,685	-$ 2,538,034		-$ 37,095,719	$ 9,026,035	$ 894,004		$ 9,920,039	-$ 27,175,680
						$ -				$ -	$ -
		Sub-Total	**$ 271,797,847**	**$ 12,447,874**	**-$ 1,335,827**	**$ 282,909,893**	**-$ 136,237,053**	**-$ 6,555,735**	**$ 1,234,585**	**-$ 141,558,202**	**$ 141,351,691**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 271,797,847**	**$ 12,447,874**	**-$ 1,335,827**	**$ 282,909,893**	**-$ 136,237,053**	**-$ 6,555,735**	**$ 1,234,585**	**-$ 141,558,202**	**$ 141,351,691**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 6,555,735**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 6,555,735

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			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 4,754,578	$ 361,773		$ 5,116,350	-$ 4,016,112	-$ 428,997		-$ 4,445,108	$ 671,242
CEC	1612	Land Rights (Formally known as Account 1906)	$ 1,604,397			$ 1,604,397	-$ 1,153,657	-$ 57,099		-$ 1,210,756	$ 393,641
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,638			-$ 111,638	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 6,845,044	$ 199,245		$ 7,044,289	-$ 2,209,176	-$ 171,859		-$ 2,381,035	$ 4,663,254
47	1820	Distribution Station Equipment <50 kV	$ 6,969,921	$ 149,716		$ 7,119,637	-$ 3,485,208	-$ 145,211		-$ 3,630,419	$ 3,489,219
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 54,165,898	$ 2,012,203	-$ 372,296	$ 55,805,805	-$ 26,945,094	-$ 668,210	$ 353,567	-$ 27,259,737	$ 28,546,068
47	1835	Overhead Conductors & Devices	$ 39,044,434	$ 1,921,374		$ 40,965,809	-$ 13,442,250	-$ 702,254		-$ 14,144,504	$ 26,821,305
47	1840	Underground Conduit	$ 14,270,567	$ 460,877	$ 46,973	$ 14,778,417	-$ 3,409,115	-$ 264,367		-$ 3,673,482	$ 11,104,935
47	1845	Underground Conductors & Devices	$ 82,442,652	$ 3,450,393	-$ 77,773	$ 85,815,272	-$ 46,203,895	-$ 1,662,138	$ 30,800	-$ 47,835,232	$ 37,980,040
47	1850	Line Transformers	$ 45,434,847	$ 2,722,711	-$ 209,625	$ 47,947,933	-$ 24,702,226	-$ 1,021,843	$ 187,448	-$ 25,536,622	$ 22,411,311
47	1855	Services (Overhead & Underground)	$ 11,110,940	$ 1,668,143		$ 12,779,084	-$ 2,908,903	-$ 477,780		-$ 3,386,684	$ 9,392,400
47	1860	Meters	$ 5,523,228	$ 597,680	-$ 95,866	$ 6,025,041	-$ 1,952,653	-$ 312,816	$ 80,663	-$ 2,184,805	$ 3,840,236
47	1860	Meters (Smart Meters)	$ 6,506,713	$ 273,165	-$ 28,436	$ 6,751,442	-$ 3,167,412	-$ 457,236	$ 10,135	-$ 3,614,512	$ 3,136,930
47	1875	Street Lighting and Signal Systems	$ 21,835			$ 21,835	-$ 11,513	-$ 873		-$ 12,387	$ 9,449
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 18,679,787	$ 2,037,896		$ 20,717,683	-$ 4,132,298	-$ 316,399		-$ 4,448,697	$ 16,268,986
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,856,959	$ 84,704		$ 1,941,663	-$ 1,428,546	-$ 86,980		-$ 1,515,526	$ 426,137
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 320,323			-$ 320,323	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 3,624,650	$ 193,149		$ 3,817,799	-$ 2,868,161	-$ 293,812		-$ 3,161,973	$ 655,826
10	1930	Transportation Equipment	$ 9,762,133	$ 599,766	-$ 40,521	$ 10,321,378	-$ 4,603,157	-$ 576,532	$ 40,521	-$ 5,139,168	$ 5,182,210
8	1935	Stores Equipment	$ 328,494			$ 328,494	-$ 262,183	-$ 14,028		-$ 276,211	$ 52,284
8	1940	Tools, Shop & Garage Equipment	$ 2,355,710	$ 91,841		$ 2,447,550	-$ 1,923,013	-$ 83,161		-$ 2,006,173	$ 441,377
8	1945	Measurement & Testing Equipment	$ 204,006			$ 204,006	-$ 203,569	$ -		-$ 203,569	$ 438
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 1,470,680	$ 122,559		$ 1,593,239	-$ 438,208	-$ 77,244		-$ 515,453	$ 1,077,787
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951			$ 72,951	-$ 72,951			-$ 72,951	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 37,095,719	-$ 5,462,680		-$ 42,558,399	$ 9,920,039	$ 1,002,764		$ 10,922,804	-$ 31,635,595
						$ -	$ -			$ -	$ -
		Sub-Total	**$ 282,909,893**	**$ 11,484,513**	**-$ 777,544**	**$ 293,616,862**	**-$ 141,558,202**	**-$ 6,816,073**	**$ 703,134**	**-$ 147,671,141**	**$ 145,945,721**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 282,909,893**	**$ 11,484,513**	**-$ 777,544**	**$ 293,616,862**	**-$ 141,558,202**	**-$ 6,816,073**	**$ 703,134**	**-$ 147,671,141**	**$ 145,945,721**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 6,816,073**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 6,816,073

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CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 5,116,350	$ 341,000		$ 5,457,350	-$ 4,445,108	-$ 445,326		-$ 4,890,435	$ 566,916
CEC	1612	Land Rights (Formally known as Account 1906)	$ 1,604,397			$ 1,604,397	-$ 1,210,756	-$ 57,099		-$ 1,267,854	$ 336,542
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,638			-$ 111,638	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 7,044,289			$ 7,044,289	-$ 2,381,035	-$ 174,900		-$ 2,555,934	$ 4,488,355
47	1820	Distribution Station Equipment <50 kV	$ 7,119,637	$ 75,000		$ 7,194,637	-$ 3,630,419	-$ 146,874		-$ 3,777,293	$ 3,417,344
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 55,805,805	$ 2,273,675		$ 58,079,479	-$ 27,259,737	-$ 707,327		-$ 27,967,064	$ 30,112,415
47	1835	Overhead Conductors & Devices	$ 40,965,809	$ 2,074,044		$ 43,039,853	-$ 14,144,504	-$ 729,106		-$ 14,873,610	$ 28,166,243
47	1840	Underground Conduit	$ 14,778,417	$ 2,459,942		$ 17,238,359	-$ 3,673,482	-$ 294,045		-$ 3,967,527	$ 13,270,832
47	1845	Underground Conductors & Devices	$ 85,815,272	$ 4,444,617		$ 90,259,889	-$ 47,835,232	-$ 1,755,909		-$ 49,591,141	$ 40,668,748
47	1850	Line Transformers	$ 47,947,933	$ 1,430,861	-$ 255,000	$ 49,123,794	-$ 25,536,622	-$ 1,074,420	$ 255,000	-$ 26,356,041	$ 22,767,753
47	1855	Services (Overhead & Underground)	$ 12,779,084	$ 1,318,899		$ 14,097,982	-$ 3,386,684	-$ 537,521		-$ 3,924,205	$ 10,173,777
47	1860	Meters	$ 6,025,041	$ 528,960		$ 6,554,001	-$ 2,184,805	-$ 339,461		-$ 2,524,266	$ 4,029,735
47	1860	Meters (Smart Meters)	$ 6,751,442	$ 230,000		$ 6,981,442	-$ 3,614,512	-$ 471,720		-$ 4,086,232	$ 2,895,210
47	1875	Street Lighting and Signal Systems	$ 21,835			$ 21,835	-$ 12,387	-$ 873		-$ 13,260	$ 8,575
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 20,717,683	$ 1,768,100		$ 22,485,783	-$ 4,448,697	-$ 348,269		-$ 4,796,965	$ 17,688,818
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,941,663	$ 94,300		$ 2,035,963	-$ 1,515,526	-$ 87,365		-$ 1,602,890	$ 433,072
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 320,323			-$ 320,323	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 3,817,799	$ 170,100		$ 3,987,899	-$ 3,161,973	-$ 271,111		-$ 3,433,085	$ 554,814
10	1930	Transportation Equipment	$ 10,321,378	$ 190,000	-$ 26,853	$ 10,484,525	-$ 5,139,168	-$ 603,744	$ 26,853	-$ 5,716,059	$ 4,768,466
8	1935	Stores Equipment	$ 328,494			$ 328,494	-$ 276,211	-$ 10,927		-$ 287,138	$ 41,357
8	1940	Tools, Shop & Garage Equipment	$ 2,447,550	$ 64,700		$ 2,512,250	-$ 2,006,173	-$ 84,741		-$ 2,090,914	$ 421,336
8	1945	Measurement & Testing Equipment	$ 204,006			$ 204,006	-$ 203,569			-$ 203,569	$ 438
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 1,593,239	$ 100,000		$ 1,693,239	-$ 515,453	-$ 83,444		-$ 598,896	$ 1,094,343
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951			$ 72,951	-$ 72,951			-$ 72,951	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 42,558,399	-$ 3,854,173		-$ 46,412,572	$ 10,922,804	$ 1,126,809		$ 12,049,613	-$ 34,362,959
						$ -	$ -			$ -	$ -
		Sub-Total	**$ 293,616,862**	**$ 13,710,025**	**-$ 281,853**	**$ 307,045,034**	**-$ 147,671,141**	**-$ 7,097,373**	**$ 281,853**	**-$ 154,486,661**	**$ 152,558,373**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 293,616,862**	**$ 13,710,025**	**-$ 281,853**	**$ 307,045,034**	**-$ 147,671,141**	**-$ 7,097,373**	**$ 281,853**	**-$ 154,486,661**	**$ 152,558,373**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 7,097,373**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 7,097,373

Accounting Standard MIFRS
Year **2021**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 5,457,350	$ 274,300		$ 5,731,650	-$ 4,890,435	-$ 237,950		-$ 5,128,385	$ 603,266
CEC	1612	Land Rights (Formally known as Account 1906)	$ 1,604,397			$ 1,604,397	-$ 1,267,854	-$ 57,099		-$ 1,324,953	$ 279,443
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,638			-$ 111,638	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 7,044,289	$ 1,699,597		$ 8,743,886	-$ 2,555,934	-$ 194,617		-$ 2,750,551	$ 5,993,335
47	1820	Distribution Station Equipment <50 kV	$ 7,194,637			$ 7,194,637	-$ 3,777,293	-$ 146,874		-$ 3,924,167	$ 3,270,470
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 58,079,479	$ 3,336,537		$ 61,416,016	-$ 27,967,064	-$ 763,325		-$ 28,730,389	$ 32,685,628
47	1835	Overhead Conductors & Devices	$ 43,039,853	$ 2,045,593		$ 45,085,446	-$ 14,873,610	-$ 757,946		-$ 15,631,556	$ 29,453,890
47	1840	Underground Conduit	$ 17,238,359	$ 2,303,907		$ 19,542,266	-$ 3,967,527	-$ 341,684		-$ 4,309,211	$ 15,233,055
47	1845	Underground Conductors & Devices	$ 90,259,889	$ 3,101,363		$ 93,361,252	-$ 49,591,141	-$ 1,866,077		-$ 51,457,218	$ 41,904,034
47	1850	Line Transformers	$ 49,123,794	$ 1,811,567	-$ 255,000	$ 50,680,361	-$ 26,356,041	-$ 1,114,107	$ 255,000	-$ 27,215,148	$ 23,465,213
47	1855	Services (Overhead & Underground)	$ 14,097,982	$ 1,436,461		$ 15,534,443	-$ 3,924,205	-$ 592,628		-$ 4,516,833	$ 11,017,610
47	1860	Meters	$ 6,554,001	$ 267,900		$ 6,821,901	-$ 2,524,266	-$ 337,283		-$ 2,861,549	$ 3,960,352
47	1860	Meters (Smart Meters)	$ 6,981,442	$ 263,750		$ 7,245,192	-$ 4,086,232	-$ 488,179		-$ 4,574,411	$ 2,670,781
47	1875	Street Lighting and Signal Systems	$ 21,835			$ 21,835	-$ 13,260	-$ 873		-$ 14,133	$ 7,702
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 22,485,783	$ 235,500		$ 22,721,283	-$ 4,796,965	-$ 381,597		-$ 5,178,563	$ 17,542,721
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 2,035,963	$ 79,100		$ 2,115,063	-$ 1,602,890	-$ 91,573		-$ 1,694,464	$ 420,599
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 320,323			-$ 320,323	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 3,987,899	$ 338,780		$ 4,326,679	-$ 3,433,085	-$ 272,448		-$ 3,705,533	$ 621,146
10	1930	Transportation Equipment	$ 10,484,525	$ 546,000	-$ 310,057	$ 10,720,468	-$ 5,716,059	-$ 612,960	$ 310,057	-$ 6,018,962	$ 4,701,506
8	1935	Stores Equipment	$ 328,494			$ 328,494	-$ 287,138	-$ 9,896		-$ 297,034	$ 31,460
8	1940	Tools, Shop & Garage Equipment	$ 2,512,250	$ 77,300		$ 2,589,550	-$ 2,090,914	-$ 86,467		-$ 2,177,381	$ 412,169
8	1945	Measurement & Testing Equipment	$ 204,006			$ 204,006	-$ 203,569			-$ 203,569	$ 438
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 1,693,239	$ 125,000		$ 1,818,239	-$ 598,896	-$ 89,065		-$ 687,961	$ 1,130,278
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951			$ 72,951	-$ 72,951			-$ 72,951	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 46,412,572	-$ 2,583,228		-$ 48,995,800	$ 12,049,613	$ 1,211,588		$ 13,261,201	-$ 35,734,599
						$ -	$ -			$ -	$ -
		Sub-Total	**$ 307,045,034**	**$ 15,359,428**	**-$ 565,057**	**$ 321,839,404**	**-$ 154,486,661**	**-$ 7,231,063**	**$ 565,057**	**-$ 161,152,666**	**$ 160,686,738**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 307,045,034**	**$ 15,359,428**	**-$ 565,057**	**$ 321,839,404**	**-$ 154,486,661**	**-$ 7,231,063**	**$ 565,057**	**-$ 161,152,666**	**$ 160,686,738**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 7,231,063**			

			Less: *Fully Allocated Depreciation*		
10		Transportation	Transportation		
8		Stores Equipment	Stores Equipment		
			Net Depreciation	-$ 7,231,063	

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing, or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-2

OEB Appendix 2-Z

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Commodity Expense

Step 1: **2020 Forecasted Commodity Prices**

Forecasted Commodity Prices

Table 1: Average RPP Supply Cost Summary*

			non-RPP	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$20.09	$20.09
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$106.94	$106.94
Adjustments ($/MWh)				$1.00
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$128.03**

Step 2: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Commodity

Customer		Revenue	Expense		2020 Bridge Year					
Class Name	UoM	USA #	USA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705			16,746,455	447,514,877	$ 0.02009	$ 0.12803	$57,631,766
General Service < 50 kW	kWh	4010	4705			24,056,286	110,995,393	$ 0.02009	$ 0.12803	$14,694,031
General Service 50 to 4999 kW	kWh	4035	4705	224,187,185		446,749,116	26,512,021	$ 0.02009	$ 0.12803	$16,873,444
Unmetered Scattered Load	kWh	4010	4705			0	1,595,465	$ 0.02009	$ 0.12803	$204,267
Sentinel Lighting	kWh	4025	4705			0	228,861	$ 0.02009	$ 0.12803	$29,301
Street Lighting	kWh	4025	4705			4,635,893	0	$ 0.02009	$ 0.12803	$93,135
	kWh	4025	4705					$ 0.02009	$ 0.12803	$0
	kWh	4025	4705					$ 0.02009	$ 0.12803	$0
	kWh	4025	4705					$ 0.02009	$ 0.12803	$0
TOTAL				**224,187,185**		**492,187,750**	**586,846,617**			**$89,525,945**

Class A - non-RPP Global Adjustment

Customer		Revenue	Expense	Amount	kWh Volume		Hist. Avg GA/kWh ***	Amount
					2020			
General Service 50 to 4999 kW		4035	4707		224,187,185		$0.0684	$15,334,198
		4010	4707					$0
		4010	4707					
				-	224,187,185			**$15,334,198**

Class B - non-RPP Global Adjustment

Customer		Revenue	Expense		2020					Amount

Class Name	UoM	USA #	USA #			Class B Non-RPP Volume			GA Rate/kWh	
Residential	kWh	4006	4707			16,746,455			$ 0.10694	$1,790,866
General Service < 50 kW	kWh	4010	4707			24,056,286			$ 0.10694	$2,572,579
General Service 50 to 4999 kW	kWh	4035	4707			446,749,116			$ 0.10694	$47,775,350
Unmetered Scattered Load	kWh	4010	4707			0			$ 0.10694	$0
Sentinel Lighting	kWh	4025	4707			0			$ 0.10694	$0
Street Lighting	kWh	4025	4707			4,635,893			$ 0.10694	$495,762
	kWh	4025	4707							$0
	kWh	4025	4707							$0
Total Volume						**492,187,750**				
TOTAL										**$52,634,558**

*Regulated Price Plan Prices for the Period November 1, 2019 – October 31, 2020

** Enter 2020 load forecast data by class based on the most recent 12-month historic Class A and Class B RPP/Non-RPP proportions

*** Based on average $ GA per kWh billed to class A customers for most recent 12-month historical year.

Cost of Power Calculation

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All Volume should be loss adjusted with the exception of:
* Volume loss adjusted less WMP
** No loss adjustment for kWh

		2020 Bridge Year	**RPP**		**2020 Bridge Year**	**non-RPP**		**Total**	
Electricity Commodity	**Units**	Volume	Rate	$	Volume	Rate	$	$	
Class per Load Forecast				-					
Residential	kWh	447,514,877		57,295,330	16,746,455		336,436		
General Service < 50 kW	kWh	110,995,393		14,210,740	24,056,286		483,291		
General Service 50 to 4999 kW	kWh*	26,512,021		3,394,334	670,936,301		13,479,110		
Unmetered Scattered Load	kWh*	1,595,465		204,267	0		-		
Sentinel Lighting	kWh	228,861		29,301	0		-		
Street Lighting	kWh	0		-	4,635,893		93,135		
	kWh	0		-	0		-		
SUB-TOTAL		586,846,617		75,133,972	716,374,935		14,391,972	$ 89,525,945	OK

Global Adjustment non-RPP	**Units**	Volume	Rate	$	Volume	Rate	$	Total	
Class per Load Forecast									
Residential	kWh			0			1,790,866		
General Service < 50 kW	kWh			0			2,572,579		
General Service 50 to 4999 kW	kWh*			0			63,109,549		
Unmetered Scattered Load	kWh*			0			-		
Sentinel Lighting	kWh			0			-		
Street Lighting	kWh			0			495,762		
	kWh			0			-		
SUB-TOTAL		0		0			67,968,756	$ 67,968,756	OK

Transmission - Network		Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential	kWh	447,514,877	0.0074	3,311,610	16,746,455	0.0074	123,924	
General Service < 50 kW	kWh	110,995,393	0.0067	743,669	24,056,286	0.0067	161,177	
General Service 50 to 4999 kW	kW	64,709	2.7628	178,778	1,637,582	2.7628	4,524,312	
Unmetered Scattered Load	kWh	1,595,465	0.0067	10,690	0	0.0067	-	
Sentinel Lighting	kW	652	2.0455	1,334	0	2.0455	-	
Street Lighting	kW	-	2.0884	-	12,418	2.0884	25,934	
				-			-	
SUB-TOTAL				4,246,081			4,835,346	9,081,428

Transmission - Connection		Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential	kWh	447,514,877	0.0054	2,416,580	16,746,455	0.0054	90,431	
General Service < 50 kW	kWh	110,995,393	0.0047	521,678	24,056,286	0.0047	113,065	
General Service 50 to 4999 kW	kW	64,709	1.9004	122,973	1,637,582	1.9004	3,112,061	
Unmetered Scattered Load	kWh	1,595,465	0.0047	7,499	0	0.0047	-	
Sentinel Lighting	kW	652	1.5881	1,036	0	1.5881	-	
Street Lighting	kW	-	1.46	-	12,418	1.46	18,130	
				-	0		-	
SUB-TOTAL				3,069,766			3,333,687	6,403,453

Wholesale Market Service		Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								

Residential	kWh	447,514,877	0.0034	1,521,551	16,746,455	0.0034	56,938	
General Service < 50 kW	kWh	110,995,393	0.0034	377,384	24,056,286	0.0034	81,791	
General Service 50 to 4999 kW (Class B)	kWh	26,512,021	0.0034	90,141	446,749,116	0.0034	1,518,947	
Unmetered Scattered Load	kWh	1,595,465	0.0034	5,425	0	0.0034	-	
Sentinel Lighting	kWh	228,861	0.0034	778	0	0.0034	-	
Street Lighting	kWh	-	0.0034	-	4,635,893	0.0034	15,762	
General Service 50 to 4999 kW (Class A)	kWh			-	224,187,185	0.0037	827,025	
SUB-TOTAL				1,995,278			2,500,464	4,495,742

RRRP								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	447,514,877	0.0005	223,757	16,746,455	0.0005	8,373	
General Service < 50 kW	kWh	110,995,393	0.0005	55,498	24,056,286	0.0005	12,028	
General Service 50 to 4999 kW	kWh	26,512,021	0.0005	13,256	670,936,301	0.0005	335,468	
Unmetered Scattered Load	kWh	1,595,465	0.0005	798	0	0.0005	-	
Sentinel Lighting	kWh	228,861	0.0005	114	0	0.0005	-	
Street Lighting	kWh	-	0.0005	-	4,635,893	0.0005	2,318	
	kWh	-	0.0005	-	0	0.0005	-	
SUB-TOTAL				293,423			358,187	651,611

Low Voltage - No TLF adjustment								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh**	427,058,763	0.0005	213,529	15,980,967	0.0005	7,990	
General Service < 50 kW	kWh**	105,921,741	0.0004	42,369	22,956,662	0.0004	9,183	
General Service 50 to 4999 kW	kW	64,709	0.1612	10,431	1,637,582	0.1612	263,978	
Unmetered Scattered Load	kWh**	1,522,536	0.0004	609	0	0.0004	-	
Sentinel Lighting	kW	652	0.1347	88	0	0.1347	-	
Street Lighting	kW	-	0.1239	-	12,418	0.1239	1,539	
				-			-	
SUB-TOTAL		534568401.2		267,026			282,690	549,716

Smart Meter Entity Charge								
Class per Load Forecast		Customers	Rate	$	Customers	Rate	$	Total
Residential		49,508	0.57	338,633	1,853	0.57	12,672.00	
General Service < 50 kW		3,705	0.57	25,341	803	0.57	5,492.20	
				-				
SUB-TOTAL				363,974			18,164	382,139
SUB- TOTAL				85,369,522			93,689,267	179,058,789
ORECA CREDIT	31.80%			(27,147,508)			0	(27,147,508)
TOTAL				**58,222,014**			**93,689,267**	**151,911,281**

***The ORRECA Credit of 31.8% will only apply to RPP proportion of the listed components. Impacts on distribution charges are excluded for the purpose of calculating the cost of power.

2020 Bridge Year - CoP		
4705 -Power Purchased	$	89,525,945
4707- Global Adjustment	$	67,968,756
4708-Charges-WMS	$	5,147,353
4714-Charges-NW	$	9,081,428
4716-Charges-CN	$	6,403,453
4750-Charges-LV	$	549,716
4751-IESO SME	$	382,139
Misc A/R or A/P	$	(27,147,508)
TOTAL	**$**	**151,911,281**

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Commodity Expense

Step 1: **2021 Forecasted Commodity Prices**

Forecasted Commodity Prices	Table 1: Average RPP Supply Cost Summary*		**non-RPP**	**RPP**
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$20.09	$20.09
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$106.94	$106.94
Adjustments ($/MWh)				$1.00
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$128.03**

Step 2: **Commodity Expense**
(volumes for the bridge and test year are loss adjusted)

Commodity

					2021 Test Year					
Customer		**Revenue**	**Expense**							
Class Name	UoM	USA #	USA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705			17,090,770	456,715,993	$ 0.02009	$ 0.12803	$58,816,702
General Service < 50 kW	kWh	4010	4705			24,498,245	113,034,586	$ 0.02009	$ 0.12803	$14,963,988
General Service 50 to 4999 kW	kWh	4035	4705	222,971,416		472,393,622	28,033,876	$ 0.02009	$ 0.12803	$17,559,061
Unmetered Scattered Load	kWh	4010	4705			0	1,544,163	$ 0.02009	$ 0.12803	$197,699
Sentinel Lighting	kWh	4025	4705			0	227,843	$ 0.02009	$ 0.12803	$29,171
Street Lighting	kWh	4025	4705			4,657,774	0	$ 0.02009	$ 0.12803	$93,575
	kWh	4025	4705					$ 0.02009	$ 0.12803	$0
	kWh	4025	4705					$ 0.02009	$ 0.12803	$0
	kWh	4025	4705					$ 0.02009	$ 0.12803	$0
TOTAL				**222,971,416**		**518,640,410**	**599,556,461**			**$91,660,195**

Class A - non-RPP Global Adjustment

					2021					
Customer		**Revenue**	**Expense**	**Amount**	**kWh Volume**				**Hist. Avg GA/kWh *** **	**Amount**
General Service 50 to 4999 kW		4035	4707		222,971,416				$0.0684	$15,251,041
		4010	4707							$0
		4010	4707							
				-	222,971,416					**$15,251,041**

Class B - non-RPP Global Adjustment

					2021					
Customer		**Revenue**	**Expense**							Amount

Class Name	UoM	USA #	USA #			Class B Non-RPP Volume			GA Rate/kWh	
Residential	kWh	4006	4707			17,090,770			$ 0.10694	$1,827,687
General Service < 50 kW	kWh	4010	4707			24,498,245			$ 0.10694	$2,619,842
General Service 50 to 4999 kW	kWh	4035	4707			472,393,622			$ 0.10694	$50,517,774
Unmetered Scattered Load	kWh	4010	4707			0			$ 0.10694	$0
Sentinel Lighting	kWh	4025	4707			0			$ 0.10694	$0
Street Lighting	kWh	4025	4707			4,657,774			$ 0.10694	$498,102
	kWh	4025	4707							$0
	kWh	4025	4707							$0
Total Volume						**518,640,410**				
TOTAL										**$55,463,405**

*Regulated Price Plan Prices for the Period November 1, 2019 – October 31, 2020

** Enter 2020 load forecast data by class based on the most recent 12-month historic Class A and Class B RPP/Non-RPP proportions

*** Based on average $ GA per kWh billed to class A customers for most recent 12-month historical year.

Cost of Power Calculation

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All Volume should be loss adjusted with the exception of:
* Volume loss adjusted less WMP
** No loss adjustment for kWh

Electricity Commodity	**Units**	**2021 Test Year** Volume	**RPP** Rate	$	**2021 Test Year** Volume	**non-RPP** Rate	$	**Total** $	
Class per Load Forecast				-					
Residential	kWh	456,715,993		58,473,349	17,090,770		343,354		
General Service < 50 kW	kWh	113,034,586		14,471,818	24,498,245		492,170		
General Service 50 to 4999 kW	kWh*	28,033,876		3,589,177	695,365,038		13,969,884		
Unmetered Scattered Load	kWh*	1,544,163		197,699	0		-		
Sentinel Lighting	kWh	227,843		29,171	0		-		
Street Lighting	kWh	0		-	4,657,774		93,575		
	kWh	0		-	0		-		
SUB-TOTAL		599,556,461		76,761,214	741,611,827		14,898,982	$ 91,660,195	OK

Global Adjustment non-RPP	**Units**	Volume	Rate	$	Volume	Rate	$	Total	
Class per Load Forecast									
Residential	kWh			0			1,827,687		
General Service < 50 kW	kWh			0			2,619,842		
General Service 50 to 4999 kW	kWh*			0			65,768,815		
Unmetered Scattered Load	kWh*			0			-		
Sentinel Lighting	kWh			0			-		
Street Lighting	kWh			0			498,102		
	kWh			0			-		
SUB-TOTAL		0		0			70,714,446	$ 70,714,446	OK

Transmission - Network		Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential	kWh	456,715,993	0.0072	3,288,355	17,090,770	0.0072	123,054	
General Service < 50 kW	kWh	113,034,586	0.0065	734,725	24,498,245	0.0065	159,239	
General Service 50 to 4999 kW	kW	68,797	2.6864	184,815	1,706,460	2.6864	4,584,235	
Unmetered Scattered Load	kWh	1,544,163	0.0065	10,037	0	0.0065	-	
Sentinel Lighting	kW	653	1.9889	1,299	0	1.9889	-	
Street Lighting	kW	-	2.0306	-	12,545	2.0306	25,473	
				-			-	
SUB-TOTAL				4,219,231			4,892,000	9,111,231

Transmission - Connection		Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential	kWh	456,715,993	0.0052	2,374,923	17,090,770	0.0052	88,872	
General Service < 50 kW	kWh	113,034,586	0.0045	508,656	24,498,245	0.0045	110,242	
General Service 50 to 4999 kW	kW	68,797	1.8247	125,533	1,706,460	1.8247	3,113,778	
Unmetered Scattered Load	kWh	1,544,163	0.0045	6,949	0	0.0045	-	
Sentinel Lighting	kW	653	1.5248	996	0	1.5248	-	
Street Lighting	kW	-	1.4018	-	12,545	1.4018	17,585	
				-	0		-	
SUB-TOTAL				3,017,056			3,330,477	6,347,534

Wholesale Market Service		Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								

Residential	kWh	456,715,993	0.0034	1,552,834	17,090,770	0.0034	58,109	
General Service < 50 kW	kWh	113,034,586	0.0034	384,318	24,498,245	0.0034	83,294	
General Service 50 to 4999 kW (Class B)	kWh	28,033,876	0.0034	95,315	472,393,622	0.0034	1,606,138	
Unmetered Scattered Load	kWh	1,544,163	0.0034	5,250	0	0.0034	-	
Sentinel Lighting	kWh	227,843	0.0034	775	0	0.0034	-	
Street Lighting	kWh	-	0.0034	-	4,657,774	0.0034	15,836	
General Service 50 to 4999 kW (Class A)	kWh			-	222,971,416	0.0037	822,540	
SUB-TOTAL				2,038,492			2,585,918	4,624,410

RRRP								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	456,715,993	0.0005	228,358	17,090,770	0.0005	8,545	
General Service < 50 kW	kWh	113,034,586	0.0005	56,517	24,498,245	0.0005	12,249	
General Service 50 to 4999 kW	kWh	28,033,876	0.0005	14,017	695,365,038	0.0005	347,683	
Unmetered Scattered Load	kWh	1,544,163	0.0005	772	0	0.0005	-	
Sentinel Lighting	kWh	227,843	0.0005	114	0	0.0005	-	
Street Lighting	kWh	-	0.0005	-	4,657,774	0.0005	2,329	
	kWh	-	0.0005	-	0	0.0005	-	
SUB-TOTAL				299,778			370,806	670,584

Low Voltage - No TLF adjustment								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh**	438,215,738	0.0014	613,502	16,398,472	0.0014	22,958	
General Service < 50 kW	kWh**	108,455,879	0.0012	130,147	23,505,891	0.0012	28,207	
General Service 50 to 4999 kW	kW	68,797	0.4776	32,857	1,706,460	0.4776	815,006	
Unmetered Scattered Load	kWh**	1,481,614	0.0012	1,778	0	0.0012	-	
Sentinel Lighting	kW	653	0.3991	261	0	0.3991	-	
Street Lighting	kW	-	0.3669	-	12,545	0.3669	4,603	
				-			-	
SUB-TOTAL		548,222,679		778,545			870,773	1,649,318

Smart Meter Entity Charge								
Class per Load Forecast		Customers	Rate	$	Customers	Rate	$	Total
Residential		50,062	0.57	342,422	1,873	0.57	12,813.76	
General Service < 50 kW		3,732	0.57	25,528	809	0.57	5,532.69	
				-				
SUB-TOTAL				367,949			18,346	386,296
SUB- TOTAL				87,482,265			97,681,749	185,164,014
ORECA CREDIT	31.80%			(27,819,360)			0	(27,819,360)
TOTAL				**59,662,905**			**97,681,749**	**157,344,654**

***The ORRECA Credit of 31.8% will only apply to RPP proportion of the listed components. Impacts on distribution charges are excluded for the purpose of calculating the cost of power.

2020 Test Year - CoP		
4705 -Power Purchased	$	91,660,195
4707- Global Adjustment	$	70,714,446
4708-Charges-WMS	$	5,294,994
4714-Charges-NW	$	9,111,231
4716-Charges-CN	$	6,347,534
4750-Charges-LV	$	1,649,318
4751-IESO SME	$	386,296
Misc A/R or A/P	$	(27,819,360)
TOTAL	**$**	**157,344,654**
		-

Appendix 2-3

OEB Appendix 2-AB

TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

2021

CATEGORY	Historical Period (previous plan[1] & actual)															
	2015			2016			2017			2018			2019			
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '0
System Access	2,438	7,463	206.1%	2,683	6,490	141.9%	3,005	5,701	89.7%	3,944	5,993	51.9%	5,973	7,974	33.5%	9,488
System Renewal	6,771	4,176	-38.3%	3,442	5,626	63.5%	6,587	5,535	-16.0%	5,776	5,256	-9.0%	4,726	4,032	-14.7%	4,247
System Service	1,028	1,845	79.4%	4,932	1,733	-64.9%	1,497	1,259	-15.9%	1,677	1,392	-17.0%	1,177	1,572	33.6%	1,202
General Plant	1,489	1,538	3.3%	1,616	1,578	-2.3%	2,513	2,439	-3.0%	2,580	2,345	-9.1%	3,245	3,369	3.8%	2,628
TOTAL EXPENDITURE	11,727	15,022	28.1%	12,673	15,426	21.7%	13,602	14,933	9.8%	13,977	14,986	7.2%	15,122	16,947	12.1%	17,564
Capital Contributions	- 828	- 5,600	576.5%	- 800	- 4,031	403.9%	- 1,537	- 2,471	60.8%	- 2,135	- 2,538	18.9%	- 2,187	- 5,463	149.8%	- 3,854
Net Capital Expenditures	10,899	9,421	-13.6%	11,873	11,395	-4.0%	12,065	12,462	3.3%	11,842	12,448	5.1%	12,935	11,485	-11.2%	13,710
System O&M	$ 16,425	$ 16,873	2.7%	$ 16,434	$ 17,147	4.3%	$ 17,671	$ 18,268	3.4%	$ 18,004	$ 18,021	0.1%	$ 19,412	$ 19,159	-1.3%	$ 19,623

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last OEB-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant including the Bridge Year.
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Notes on year over year Plan vs. Actual variances for Total Expenditures

Notes on Plan vs. Actual variance trends for individual expenditure categories

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2020		**Forecast Period** (planned)				
Actual[2]	Var	2021	2022	2023	2024	2025
'00	%	$ '000				
9,488	0.0%	8,466	6,347	6,490	5,196	5,197
4,247	0.0%	6,828	7,986	7,314	8,156	8,348
1,202	0.0%	1,098	1,099	1,350	1,602	1,600
2,628	0.0%	1,551	1,551	1,551	1,551	1,551
17,564	0.0%	17,943	16,983	16,706	16,505	16,697
- 3,854	0.0%	- 2,583	- 2,585	- 2,587	- 2,589	- 2,587
13,710	0.0%	15,359	14,398	14,119	13,916	14,110
$ 19,623	0.0%	$ 20,384	$ 20,792	$ 21,208	$ 21,632	$ 22,064

should include their planned budget in each subsequent historical year up to and

Appendix 2-4

OEB Appendix 2-AA

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Appendix 2-AA
Capital Projects Table

Projects	Reference	2015	2016	2017	2018	2019	2020 Bridge Year	2021 Test Year
Reporting Basis		**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access								
Customer Driven System Reinforcements for New Commercial Service Connections	1	849,329	736,317	933,983	1,104,336	1,022,512	2,003,964	2,301,448
Commercial Connection Projects Less Than Materiality	2	835,479	1,243,722	1,019,677	1,428,763	1,509,202		
King St. Bell Joint Use Pole Replacement	3	241,068						
NRWC Wind Farm Line Conflicts	4		607,961					
Enercon Wind Farm Line Conflicts	4		430,071					
Eptcon Stringing Conflicts	4		279,261					
FWRN LP Line Conflicts	4		210,545					
Oldfield Rd 3-Ph Pole Line	5		293,937					
Mcleod @ Montrose & Oakwood	6			166,310				
Fallsview Entertainment Complex	7				204,129			
Garner Road Line Rebuild to 3-Phase	8					223,044		
Motor Vehicle Accidents	9	80,382	115,958	258,091	179,628	147,214		
Metering	10	111,450	138,789	601,441	585,648	481,484	397,300	405,050
Warren Woods Subdivision Phase 3	11	172,667						
Oldfield Estates Subdivision Phase 1	11	160,905						
Oldfield Estates Subdivision Phase 2	11		183,381					
Warren Woods Subdivision Phase 4	11		171,972					
Warren Woods Subdivision Phase 4 Stage 2	11			184,983				
Warren Woods Subdivision Phase 5	11				237,427			
Cherry Heights Extension	11					341,970		
Vista Ridge Phase 1	11					237,541		
Warren Woods Phase 5 Stage 2	11					166,032		
Terravita Subdivision	11					148,562		
New Subdivision Projects Below Materiality	11	464,908	476,663	340,921	448,833	660,564		
New Connections in Existing Subdivisions	11	395,224	564,008	577,899	333,345	429,566	901,692	915,516
Transfer of Expansion Facilities from Customers	11	3,160,319	688,452	901,555	913,711	2,312,132	1,000,000	1,000,000
Road Relocation Projects	12	411,612	142,942	93,777	125,864	120,412	54,390	540,923
RMN - Reg Rd #18-Mountain Relocation	12	311,300						
CNF Level St U/G Relocate	12	230,733						
Clifton Hill Primary Upgrade	13		309,573					
KM3 - Link	14					11,092	876,668	
Pin Oak Main Loop	15						1,224,075	
GPI Feeder Build	16						807,178	
Thorold Stone - Bridge Roundabout	17						452,235	
Jordan UG Relocate	18						1,062,995	
RR20 Roundabouts	19						254,825	
Fallsview UG Relocate	20						452,244	
Kalar TS Additional Switchgear	21					110,321		1,699,597
Niagara South Feeders Ph 1								1,603,149
Miscellaneous	22	37,540	-103,819	622,403	431,220	52,114		
Sub-Total		7,462,916	6,489,732	5,701,039	5,992,903	7,973,762	9,487,566	8,465,683
System Renewal								
Crawford St. Rebuild - Thorold Stone to Sheldon	23	463,166						
Willodel Rd. - Gonder to Koabel	24	313,261						
Willoughby Dr. - Main to Cattell	25	12,799	458,729					
Willoughby Dr. - Cattell to Weinbrenner	26		375,385	318				
Transformer Replacements - PCB > 50 ppm	27	235,322						
Downtown core PILCDSTA Decomissioning	28		382,899	469,444	53,355	75,377		
Station 22 Rebuild - Ph 1 Carryover / Phase 2	29	682,135	202,992					
Beck Road Rebuild - Marshall to Schisler	30	170,696						
Frederica St Rebuild - Dorchester to Drummond	31	14,696	689,884	26,365				
NS&T ROW - Crossing the QEW	32		207,136	159,229				
Jordan Rd Rebuild Phase 2 - Honsberger from Jordan to Thirteenth	33	460,242						
Jordan Rd Rebuild Phase 3	33		307,408					
Jordan Rd Rebuild Phase 4	33			582,371				
Kalar TS Protection Equipment Refurbishment	34			56,943	128,308			
Kalar TS Relay Upgrade	34						75,000	
Dorchester Road Rebuild - McLeod to Dunn	35		377,755	232,048				
Concession 2 Rd - Caistorville Rd to Westbrook Rd	36					157,568		

Thorold Stone Rd Rebuild - Montrose to Kalar	37				10,017	162,768	349,274	
Portage Rd. Rebuild - Mountain to Church's Lane	38				119,863	288,298		
Campden DS Power Tx - Replace with Former Jordan DS Tx	39			35,884				
Station St. DS - Power Transformer Replacement	40			179,626				
Station 14 Voltage Conversion - Phase 1	41			399,195	2,437			
Station 14 Voltge Conversion Phase 2	41				712,832			
Station 14 Voltage Conversion - Phase 3	41					816,054	236,611	
Victoria Ave South of Fly Rd - Phase 1	42		8,936	137,553	694,069			
Victoria Ave South of Fly Rd - Phase 2	42				567,882			
Oakwood Drive - South of Smart Centre to QEW	43			11,808	583,572			
Dorchester Road Rebuild - Mountain to Riall	44		1,943	510,845	204,558			
Chippawa Redundant Supply - Phase 1	45			279,777	67,329			
Chippawa Redundant Supply - River Crossing	45				492,482			
Murray TS - J Bus Metering	46					430,258		
Victoria Ave Rebuild - 7th Ave Phase 2	47					232,172		
Campden DS Tx Failure	48					150,378		
Mountain Road - St. Paul St. to Mewburn	49					297,198		
Sinnicks Ave Rebuild - Thorold Stone to Swayze	50						824,145	
McRae St. Area Rebuild Ph 1	51						351,194	
King St. Rebuild Phase 1 - Bartlett Rd to Sann Rd.	52						344,679	
Cooper - Jill- Jordan - Marie Claude Rebuild								374,856
Prospect - Brittania - Kitchener Voltage Conversion								362,011
King St Rebuild Phase 2 - Sann Rd to Merritt Rd								578,004
Lundy's Lane OH to UG Rebuild - Phase 1								536,750
Sixteen Road Rebuild Regional Rd 14 to McCollum Rd								438,624
Regional Road 14 Sixteen Rd to Twenty Rd								547,178
Cherryhill Rebuild								433,342
McRae St. Area Rebuild Ph 2								466,673
Pole Replacements	53	546,418	583,550	1,009,358	881,938	962,984	700,988	657,323
Kiosk Replacements	54	311,260	1,165,579	937,054	122,613	80,095	52,704	646,096
Switchgear Replacements	55	201,852	222,441	205,352	164,316	308,755	86,218	380,960
Padmount Transformer Replacements								277,762
Polemount Transformer Replacements								410,463
Transformer Collar Replacements								114,635
Pole Mount Step Down Transformer Eliminations - Lincoln / West Lincoln	56						600,106	
Rolling Acres OH to UG Conversion Phase 2	57	764,211						
Rolling Acres OH to UG Conversion Phase 3	57		640,911					
Stanley TS - HONI Initiated	58						625,765	
Subdivision Rehabilitation - Phase 1	59			301,743				
Subdivision Rehabilitation Phase 2	59				450,651	69,938		
Subdivision Rehabilitation Phase 3								603,505
Sub-Total		4,176,057	5,625,547	5,534,913	5,256,221	4,031,843	4,246,684	6,828,182
System Service								
King St. 27.6 kV Extension to Martin Rd	60	130,845						
Heartland Road Extension - Brown Rd to Chippawa Creek	61			109,607				
Grid Modernization Program	62	143,148	575,200	-47,512	161,240	225,929	168,450	209,350
Glenholme to Franklin Ave - 600 MCM UG Install	63		68,207	42,618				
Brown Road Extension - Montrose to Blackburn	64			77,945				
Range Road 2 - East of Allen	65				38,951			
System Sustainment / Minor Betterments	66	1,570,562	1,089,323	1,075,854	931,129	1,274,030	873,020	888,460
Willoughby Road Extension	67				259,547			
Kalar TS Power Transformer Dry Down Equipment	68					72,501		
Greenlane Rd at Ontario - Tie Point	69				1,008		160,278	
Sub-Total		1,844,555	1,732,729	1,258,512	1,391,876	1,572,460	1,201,748	1,097,810
General Plant								
Building		468,660	52,753	403,007	1,024,864	2,037,896	1,768,100	235,500
Hardware		248,789	241,217	332,121	326,559	193,149	170,100	338,780
Software		183,006	342,477	710,896	288,891	361,773	341,000	274,300
Vehicles		490,774	792,445	876,513	518,258	599,766	190,000	546,000
General Equipment		146,974	149,531	116,016	186,335	176,544	159,000	156,400
Sub-Total		1,538,203	1,578,423	2,438,553	2,344,908	3,369,128	2,628,200	1,550,980
Total		**15,021,732**	**15,426,432**	**14,933,017**	**14,985,908**	**16,947,193**	**17,564,198**	**17,942,655**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***								
Total		**15,021,732**	**15,426,432**	**14,933,017**	**14,985,908**	**16,947,193**	**17,564,198**	**17,942,655**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

Appendix 2-5

Capitalization Policy

Niagara Peninsula Energy Inc.

Capitalization Policy for Capital Assets

The purpose of capitalizing expenditures is to provide an equitable allocation of costs among existing and future customers. As capital assets are expected to provide future economic benefits for more than one year, any expenditure incurred for the acquisition, construction, development or betterment of the capital assets should be capitalized. The capitalized costs are allocated over the estimated useful life of the assets by amortization.

The Company adopts the full cost accounting in accordance with guidance in the International Financial Reporting Standards IAS 16.

- Asset Cost
  Costs for capital assets installed or erected by the Company include:
  - Direct material
  - Direct labour
  - Directly attributable overheads for materials, labour and vehicle
  - Sub-contracting cost, if any

    Definition of cost (extract from CPA Canada Handbook – Accounting 3061.03b):

    Cost is the amount of consideration given up to acquire, construct, develop, or better an item of property, plant and equipment and includes all costs directly attributable to the acquisition, construction, development or betterment of the capital asset including installing it at the location and in the condition necessary for its intended use.

    A betterment is a cost, which is incurred to enhance the service potential of a capital asset. Expenditures for betterments are capitalized. This enhancement in service potential can include an increase in the physical output or service capacity, decrease in associated operations costs, extension in the useful life asset, or improvement in the quality of the asset's output.

    Definition of betterment (extract from CPA Canada Handbook – Accounting 3061.14):

    The cost incurred to enhance the service potential of an item of property, plant and equipment is a betterment. Service potential may be enhanced when there is an increase in the previously assessed physical output or service capacity, associated operating costs are lowered, the life or useful life is extended, or the quality of output is improved. The cost incurred in the maintenance of the service potential of an item of property, plant and equipment is a repair, not betterment. If a cost has the attributes of both a repair and a betterment, the portion considered to be a betterment is included in the cost of the asset.

- Asset Recognition

Property, plant and equipment that meet the definition of a capital asset as provided in the CPA Canada Handbook are capitalized. Expenditures that do not meet the definition are expensed in the current year.

Definition of assets (extract from CPA Canada Handbook – Accounting 1000.24):

Assets are economic resources controlled by an entity as a result of past transactions or events and from which future economic benefits may be obtained.

Assets have three essential characteristics (extract CPA Canada Handbook – Accounting 1000.25):

a. They embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows;
b. The entity can control access to the benefit; and
c. The transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred.

➢ Capitalization Threshold

Theoretically, any expenditure that meets the asset cost and asset recognition criteria would be recorded as a capital asset. However, for practical reasons, qualifying costs would only be capitalized if it has a useful life of more than one year; and the item cost is greater than $1,000.00 for readily identifiable assets. This threshold may be changed at the discretion of the Senior Vice-President Finance. Land will always be capitalized, regardless of cost.

➢ Spare transformers and meters

Spare transformers and meters are accounted for as capital assets since they form an integral part of the reliability program for a distribution system. They are not intended for resale and can be classified as property, plant and equipment in accordance the CPA Canada Handbook; Accounting Section 3031.03.

➢ Allowance for Funds Used During Construction (AFUDC)

In regard to the measurement of carrying costs of a capital asset under construction and the capitalization of interest cost, the CPA Handbook: Accounting notes that the cost of an item of property, plant and equipment that is acquired, constructed, or developed over time includes carrying costs directly attributable to the acquisition, construction, or development activity. For an item of rate-regulated property, plant and equipment, the cost includes the directly attributable allowance for funds used during construction allowed by the regulator per s.3061.11. The financing charge will be at the rate deemed by the Ontario Energy Board ("OEB") for rate setting purposes.

The company does not capitalize interest costs where capital assets are financed internally from the Company's working capital.

- Amortization

Amortization is provided on a straight-line basis for capital assets available for use over their estimated service lives, at the following rates:

Account Number	Account Description	Years	Rate	Account Number	Account Description	Years	Rate
1830	Fully Dressed Wood Poles	50	2.0%	1860	Meters - Non-Smart Meters	20	5.0%
1831	Fully Dressed Concrete Poles	60	1.7%	1861	Smart Meters	15	6.7%
1831	Fully Dressed Steel Poles	60	1.7%				
				1708	Station Building	50	2.0%
1836	OH Switch - complex (Motor & RTU)	15	6.7%	1908	Administration Buildings	60	1.7%
1835	OH Conductors & non-complex switches	60	1.7%				
1837	OH Secondary Conductor	30	3.3%	1611	Software	3	33.3%
1715	Power Transformer	45	2.2%	1915	Office Equipment	10	10.0%
1716	Station DC System	10	10.0%				
1717	TS Station Metal Clad Switchgear	40	2.5%	1931	Vans / Cars	8	12.5%
1718	Station Independent Breakers	45	2.2%	1932	Trucks & Buckets	15	6.7%
1719	Protection System	20	5.0%	1933	Trailers	20	5.0%
1820	Power Transformer	45	2.2%	1920	Hardware	5	20.0%
1821	Station Metal Clad Switchgear	30	3.3%				
				1935	Stores Equipment	10	10.0%
1840	Ducts/Concrete Encased Duct Banks/Foundations	50	2.0%				
				1940	Tools	10	10.0%
1845	Primary TR XLPE Cables in Duct	35	2.9%				
1846	UG Vault Switches & Pad-Mounted Switchgear	30	3.3%	1945	Measurement & Testing Equipment	5	20.0%
1850	OH Transformer and Voltage Regulator	40	2.5%	1955	Remote SCADA/ Wi-Max Equipment	20	5.0%
1853	Pad-Mounted Transformers and Mini-Pads	30	3.3%				

Amortization on general equipment directly used in the installation of other capital assets is capitalized to the new assets based on a pro-ration of the time during the year they are used for such purposes.

The half year rule for depreciation (IAS 16) is applied in the year of acquisition of the asset. This convention for depreciation calculates the depreciation on the basis that the assets are brought into use half way through the fiscal year. This relieves the corporation of the burden associated with tracking the dates of acquisition and disposal of an asset. Only half of the full year depreciation is allowed in the first year, the remaining balance is deducted in the final year of the depreciation schedule.

Assets that are readily identifiable, in OEB accounts 1915 to 1980, are amortized commencing the first month after the asset is put into use for the useful life of the asset.

- Disposals and Write Downs
  For all assets taken out of service, the asset cost and related accumulated amortization is removed from the records. Differences between the proceeds, if any and the unamortized asset amount plus removal costs are recorded as a gain or loss in the year of disposal.

- Betterments versus Maintenance and repairs
  Questions to determine if costs incurred are for the betterment of the capital asset or expensed as maintenance and repairs:

  - Increase in the previously assessed physical output or service capacity?
  - Lower the associated operating costs?
  - Substantial improvement in the quality of efficiency of output? (> 10%)
  - Is the life of the asset extended?

Criteria

- At least one question must be a “Yes” to qualify for betterment.

Appendix 2-6

OEB Appendix 2-D

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Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2015 Historical Year	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Bridge Year	2021 Test Year
Operations	5,351,195	5,511,542	5,731,189	5,598,324	6,087,979	6,042,983	6,052,900
Maintenance	2,345,782	2,203,115	2,660,236	2,589,112	2,678,573	2,567,275	2,577,832
Billing and Collecting	5,283,210	5,295,777	5,620,257	5,717,281	5,966,076	6,406,032	6,792,581
Community Relations	82,819	99,714	161,253	132,561	133,276	129,200	102,200
Administration & General	6,234,765	6,795,960	6,759,615	6,690,845	6,969,193	7,374,878	7,900,998
Total OM&A Before Capitalization (B)	$ 19,297,771	$ 19,906,107	$ 20,932,551	$ 20,728,124	$ 21,835,098	$ 22,520,366	$ 23,426,511

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2015 Historical Year	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Historical Year	Directly 2020 Bridge Year	2021 Test Year
Employee benefits	$ 1,383,616	$ 1,659,371	$ 1,665,078	$ 1,567,492	$ 1,573,990	$ 1,702,716	$ 1,788,330
Fleet costs	$ 1,040,714	$ 1,100,217	$ 999,035	$ 1,140,037	$ 1,102,302	$ 1,194,259	$ 1,254,171
initial delivery and handling costs							
costs of testing whether the asset is functioning properly							
professional fees							
costs of opening a new facility							
costs of introducing a new product or service (including costs of advertising and promotional activities)							
costs of conducting business in a new location or with a new class of customer (including costs of staff training)							
administration and other general overhead costs							
Insert description of additional item(s) and new rows if needed							
Total Capitalized OM&A (A)	$ 2,424,330	$ 2,759,588	$ 2,664,113	$ 2,707,529	$ 2,676,292	$ 2,896,975	$ 3,042,501

% of Capitalized OM&A (=A/B)	13%	14%	13%	13%	12%	13%	13%

Appendix 2-7

OEB Appendix 2-G

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Appendix 2-G
Service Reliability and Quality Indicators

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
SAIDI	2.311	1.685	1.508	2.352	2.428	2.051	1.519	1.369	1.982	2.028	2.051	1.519	1.369	1.982	2.028
SAIFI	1.705	1.414	1.688	1.978	1.830	1.420	1.378	1.545	1.652	1.626	1.420	1.378	1.545	1.652	1.626

5 Year Historical Average

	Including outages caused by loss of supply	Excluding outages caused by loss of supply	Excluding Major Event Days
SAIDI	2.057	1.790	1.790
SAIFI	1.723	1.524	1.524

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2015	2016	2017	2018	2019
Low Voltage Connections	90.0%	91.4%	92.7%	91.5%	93.3%	93.6%
High Voltage Connections	90.0%	94.5%	100.0%	100.0%	90.7%	100.0%
Telephone Accessibility	65.0%	82.7%	83.0%	88.0%	85.9%	84.7%
Appointments Met	90.0%	95.7%	99.8%	98.3%	98.9%	99.5%
Written Response to Enquires	80.0%	100.0%	100.0%	93.1%	86.3%	88.9%
Emergency Urban Response	80.0%	91.5%	97.1%	97.1%	100.0%	97.7%
Emergency Rural Response	80.0%	83.7%	93.5%	100.0%	100.0%	94.3%
Telephone Call Abandon Rate	10.0%	1.0%	0.9%	0.9%	1.3%	0.9%
Appointment Scheduling	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Appendix 2-8

Distribution System Plan

Niagara Peninsula Energy Inc.

Distribution System Plan

2020

Historical Period: 2015 - 2020
Forecast Period: 2021 - 2025

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EXECUTIVE SUMMARY

Niagara Peninsula Energy Inc. ("NPEI") is an Electrical Distribution Company servicing an area of approximately 820 square kilometres. NPEI's service area is composed of Niagara Falls, Lincoln, West Lincoln and the Village of Fonthill and its system contains a mix of urban and rural electrical distribution. Niagara Peninsula Energy's Mission is to deliver safe, efficient, and reliable electricity. Niagara Peninsula Energy employees provide the best possible service to all Customers, delivering environmentally responsible and sustainable energy for the future viability of our Communities.

In order to maintain the sustainability of its operations, sufficient funding to facilitate planning, equipment, personnel and systems must be in place to provide the core functions required. Establishing a sound and viable long-term plan for personnel recruitment and training, equipment procurement, software and technology tools to aid in asset management, design and modeling, communication systems, billing and accounting systems, are key to ensuring that these services are provided in an efficient and economical manner.

To demonstrate commitment to the efficient and economical provision of these services and to comply with the requirements of OEB's Chapter 5 Consolidated Distribution System Plan Filing Requirements, NPEI has developed this Distribution System Plan ("DSP"). An Asset Condition Assessment ("ACA"), developed by Kinectrics Inc., provides the basis for system renewal investments, the largest portion of NPEI's capital expenditures. The ACA was developed using data originating from regular programs established by NPEI, including sub-station maintenance and testing, pole testing, pad-mounted equipment inspections, kiosk inspections, manhole inspections, and sidewalk vault inspections. These inspection, testing, and maintenance programs are carried out by qualified contractors following criteria provided by NPEI to determine asset condition, public safety concerns, access issues, and to estimate remaining asset life. Digital images are obtained and the information is linked to the asset within the Geographic Information System (GIS), from which reports can be generated relating to quantities, age, type, condition and other relevant criteria. These reports are compiled to generate data required as input for the ACA. The Health Indices and flagged for actions strategies determined from the ACA provides data critical for long term planning and the development of the 2021 to 2025 Capital Plan as outlined in this DSP.

Understanding and responding to the preferences of NPEI's customers has been and continues to be the focus of NPEI's efforts in developing short and long-term plans. NPEI's customer base consists of residential, small and midsized business customers. Among competing outcomes, price, reliability and finding internal cost efficiencies are the top three priorities for both residential and small business customers. With respect to reliability, reducing the overall number of outages, the overall length of outages and improving restoration time are the top three priorities for both rate classes. While keeping price at a reasonable and affordable level is an important priority for customers, the majority feel that investing in the grid to maintain reliability if preferable to deferring investments to keep bills low.

Overall, NPEI's customers were supportive of its 2021-2025 draft plan as it was presented during the customer engagement process. In each of the three workbooks (Residential, Small Business and GS > 50 kW), the majority of customers surveyed indicated a preference for NPEI to either maintain the proposed rate increase to deliver a program that focuses on the priorities of its draft plan, or to improve service even if that means an increase that exceeds what is proposed in the draft plan.

In each case, however, the customer support for maintaining the proposed level of rate increase was greater than the customer support for improving service even if that means an increase that exceeds what is proposed in the draft plan.

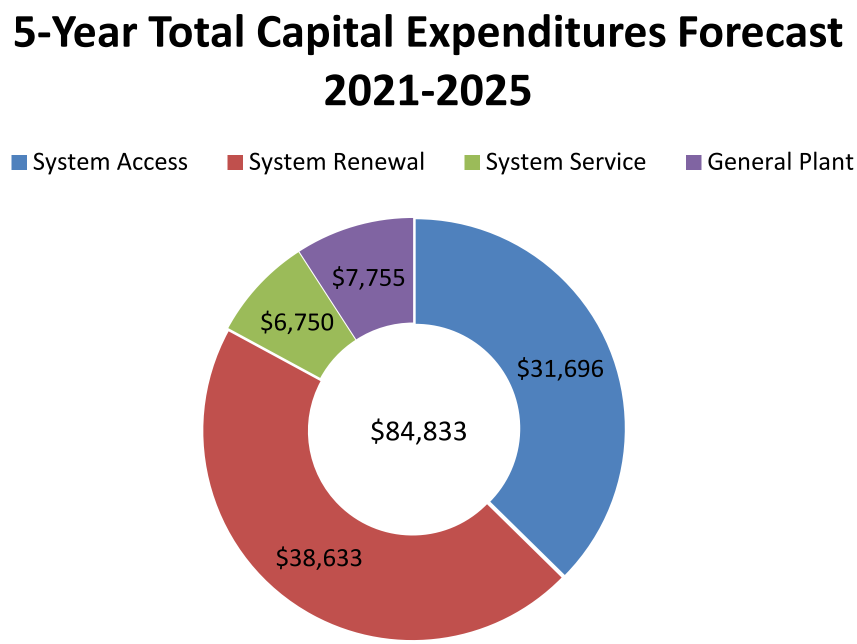
Further, among Vulnerable Residential customers, a minority (29%) indicated that NPEI should keep increases below what is proposed in the draft plan even if that means reductions in service, compared to 11% of Residential customers overall.

In determining whether to adjust the overall level of spending proposed in its draft plan, NPEI has considered the following factors:

- Balancing customer preferences in general against the preferences expressed by the more vulnerable Residential customers.
- The resulting level of bill impacts to all customer classes.
- Internal resource constraints: whether or not an increase in the overall level of proposed capital projects or programs may require additional engineering or operations resources beyond NPEI's current staffing levels.
- Financial leverage: whether or not an increase in the overall level of proposed capital projects or programs may require NPEI to incur additional debt.

Based on the above considerations, NPEI has decided to maintain the overall proposed level of capital spending consistent with what was included in the draft plan.

NPEI considers all customer feedback and preferences in determining the pacing of its investments and in optimal selection of projects. Survey results were used to inform the asset management plan and development of the capital investment plan. In addition to the customer feedback, the corporate strategic priorities and asset management objectives form the high-level framework for NPEI's investment programs. Asset management objectives identify investments that are best aligned from an overall benefit and risk management perspective. An integral part of achieving the asset management objectives are inspection, maintenance and replacement programs, to ensure system performance is sustained during the entire asset service life. To align to asset management best practices and to provide consistency with its Strategic Priorities, NPEI has adopted an asset management strategy that provides direction for the management of assets while recognizing realistic service and performance goals. The asset management strategy ensures a continual and consistent focus on delivering services in a way that balances risk and long term costs. The combination of NPEI's asset management and capital expenditure planning process leads to a capital expenditure plan consisting of a five-year capital expenditure forecast. The asset management and capital investment process identify System Access, System Renewal, System Service and General Plant requirements. These requirements result in a list of mandatory and added value investments to be executed over the investment period. The final investment portfolio considers the balance between achieving NPEI's Asset Management Objectives and the impact on customer rates. NPEI plans to invest an average of $17M in capital expenditures per year across all four investment categories for a gross total of approximately $84.8M. The figure below shows the 5-year expenditures forecast by investment category.



Expenditures in the System Access category are driven by external requirements such as servicing new customer load and relocating distribution plant to suit road authorities. These expenditures are mandatory. Specific projects such as accommodating the new Niagara South Hospital development, which is planned as multiyear projects, are budgeted for based on NPEI's estimates, in conjunction with information from external agencies. NPEI plans to invest an average of $5.68M in capital expenditures per year within the System Access category which accounts for 33.5% of the gross total over the forecast period.

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and play a crucial role in the overall reliability, safety and sustainment of the distribution system. The majority of projects found under the System Renewal framework are overhead rebuild projects which are planned for based on the condition of NPEI's in-service assets. Other programs within the System Renewal category consist of replacing individual assets such as poles, transformers and switchgear that are deemed to be at end of life due to a poor or very poor rating in the asset condition assessment. Over the DSP period, 100 poles, 73 transformers and 4 switchgears per year are planned for replacement over and above those included in the overhead rebuild projects. NPEI had strong customer support for these programs and in some cases, customers were willing to pay more to accelerate the program. Another major program planned within the forecast period is Direct Buried Subdivision Rehabilitation. The program includes installation of duct in the older subdivisions where the primary and secondary conductors were installed by direct burial. These cables are nearing end of life and will require replacement in the near future. The duct installed as part of this program will facilitate the replacement of these underground conductors. NPEI plans to invest an average of $8.05M in capital expenditures per year within the System Renewal category which accounts for 47.4% of the gross total over the forecast period.

Expenditures in the System Service category are driven by the need to ensure that the distribution system continues to meet operational objectives (such as reliability, grid flexibility and DER integration) while addressing anticipated future customer electricity service requirements. Expenditures in this category can include the installation of automated reclosers and switches, line sensors and fault indicators or conversion from overhead to underground networks to cost effectively improve system reliability and efficiency. NPEI plans to invest an average of $1.69 in capital expenditures per year within the System Service category which accounts for 9.96% of the gross total over the forecast period.

Expenditures in the General Plant category are driven by the need to modify, replace or purchase assets that are not part of the distribution system but support the utility's everyday operations. The significant program found under the General Plant framework is the Information Systems and Technology program. Expenditures in this program are driven by the need to acquire, enhance and upgrade computer hardware and software used in information technology (IT) and operation technology (OT) applications. These hardware and software tools are crucial to the day-to-day running of the organization and must be protected and secured to reduce the likelihood of cyber security breaches. In addition to maintaining the IT and OT systems, another significant driver of General Plan spending is the renewal of the operations fleet equipment. NPEI plans to invest an average of $1.55M in capital expenditures per year within the General Plant category which accounts for 9.14% of the gross total over the forecast period.

The DSP's purpose is to show how NPEI plans, manages and develops the electrical distribution system and associated infrastructure. It outlines the long term Capital Expenditure Plan to meet needs stemming from internal drivers, external drivers and strategic investments, while maintaining a reasonable impact on customers' rates and system performance.

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5.0 INTRODUCTION

The Ontario Energy Board's Filing Requirements for Electricity Transmission and Distribution Applications Chapter 5 Consolidated Distribution System Plan Filing Requirements ("Chapter 5 Filing Requirements") dated July 12, 2018, requires Local Distribution Companies ("LDC") to submit a Distribution System Plan ("DSP") as part of its Cost of Service ("COS") Distribution Rate Application. Niagara Peninsula Energy Inc. ("NPEI") has developed this DSP to comply with the filing requirements. The DSP has been prepared and formatted using the numbering and section headings as laid out in the Chapter 5 Filing Requirements.

5.0.1 Application and Scope

NPEI's DSP is a stand-alone document and is filed in support of NPEI's 2021 Cost of Service Rate Application. This DSP describes and substantiates NPEI's asset management processes and capital expenditure plan for the 2020-2025 period. The DSP documents the practices, policies and processes that are in-place to ensure that investment decisions support NPEI's desired outcomes in a cost-effective manner and provide value to customers.

5.0.2 Evaluation of the DSP

NPEI's DSP is designed to support the achievement of the four key OEB established Renewed Regulatory Framework for Electricity (RRFE) performance outcomes:

1. ***Customer Focus:*** *services are provided in a manner that responds to identified customer preferences;*
2. ***Operational Effectiveness:*** *continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;*
3. ***Public Policy Responsiveness:*** *utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and*
4. ***Financial Performance:*** *financial viability is maintained; and savings from operational effectiveness are sustainable.*

5.1 GENERAL & ADMINISTRATIVE

5.1.1 Purpose of Filing the DSP

This DSP describes how NPEI plans to develop, manage and maintain its distribution system equipment to provide a safe, secure, reliable, efficient and cost-effective service to its customers. The DSP identifies the major initiatives and projects to be undertaken over the planning period. This DSP spans an eleven-year period. The historical period is from 2015 to 2020 (2020 being the Bridge Year) and the forecast period is 2020 to 2025 (2021 being the Test Year). NPEI's last Board Approved budget was for 2020.

The DSP contains five sections and is organized using the same section headings indicated in the OEB's Filing Requirements and addresses the information outlined in each section. Other relevant information is included in separately identified sections and is intended to complement the prescribed data.

Major areas covered by this plan include; coordinated planning with third parties, performance measurement for continuous improvement, an overview of NPEI's asset management process, an overview of the assets managed and asset lifecycle optimization policies and practices, a summary of NPEI's capital expenditure plan, including an overview of the capital expenditure planning process, an assessment of the system capability for Renewable Energy Generation (REG), and justification of material projects (above the materiality threshold of $170,000).

5.1.2 Investment Categories

As per OEB requirements, the projects and programs contained within this DSP are each grouped into one of the four investment categories identified below.

	Example Drivers	Example Projects / Programs
system access	Customer service requests	- New customer connections - Modifications to existing customer connections - Expansions for customer connections or property development
	Other 3rd party infrastructure development requirements	- System modifications for property or infrastructure development (e.g. relocating pole lines for road widening)
	Mandated service obligations (DSC; Cond. of Serv.; etc.)	- Metering - Long term load transfer
system renewal	Assets/asset systems at end of service life due to: - Failure - Failure risk - Substandard performance - High performance risk - Functional obsolescence	- Programs to refurbish/replace assets or asset systems; e.g.: batteries; cable (by type); cable splices; civil works; conductor; elbows & inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type)
system service	Expected changes in load that will constrain the ability of the system to provide consistent service delivery	- Property acquisition - Capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation - Line extensions
	System operational objectives: - Safety - Reliability - Power quality - System efficiency - Other performance/functionality	- Protection & control upgrade; e.g. reclosers; tap changer controls/relays; transfer trip - Automation (new/upgrades) by device type/function - Supervisory control and data acquisition (SCADA) - Distribution loss reduction
general plant[1]	- System capital investment support - System maintenance support - Business operations efficiency - Non-system physical plant	- Land acquisition - Structures & depreciable improvements - Equipment and tools - Supplies - Finance/admin/billing software & systems - Rolling stock - Intangibles (e.g. land rights; capital contributions to other utilities)

Note: 1. Includes only 1900 series accounts

5.1.3 Timing of Filing

This DSP is being filed in support of NPEI’s 2021 Cost of Service Rate Application.

5.2 DISTRIBUTION SYSTEM PLAN

5.2.1 Distribution System Plan Overview

NPEI is an LDC serving approximately 55,434 customers in the cities and townships of Fonthill (village of Pelham), Lincoln, Niagara Falls, and West Lincoln. NPEI distributes electricity to these customers from 7 transformer stations connected to approximately 2,125 kilometres of overhead and underground circuits.

5.2.1.1 Key Elements

NPEI’s Distribution System Plan (DSP) is based on the information and input from various sources, such as core business values, customer input, asset management planning strategies, and historical capital expenditure.

NPEI's Vision and Mission statement are at the core of distribution system planning:

Vision Statement: "To be recognized as exceptional in delivering services and value, to our customers and communities"

Mission Statement: “To deliver safe, efficient and reliable electricity with excellent customer service and community value, provided by engaged employees”.

NPEI strives to achieve its mission through key corporate business values. NPEI and its staff will maintain conduct with commitment to the values of:

- Responsibility- we provide services with safety first for our customers and employees
- Integrity- we are ethical and our actions are truthful and trustworthy
- Fairness- we treat everyone equally and free of bias
- Respect- we listen to each other and see value that each member of the team brings and respect the needs of our stakeholders
- Transparency- we are open and accountable for our actions and decisions

NPEI uses 5 key strategic objectives as the basis for business planning:

- CUSTOMER SATISFACTION
    - Enhance customer satisfaction through high quality service.
    - Promote the efficient use of electricity through education, and delivery of conservation initiatives.
    - Continue to deliver reliable electricity at reasonable rates.
    - Minimize system outages.

- FACILITIES OPTIMIZATION
    - Plan expansion of the transformation and distribution systems to meet the electrical needs of current and future customers.
    - Refurbish aging plant facilities and equipment in a cost effective manner.
    - Enhance system performance and reliability

- PUBLIC POLICY

- Participate on industry advisory panels and incorporate any new legislated initiatives into the system.
- Implement Smart Grid initiatives to improve reliability and accommodate Distributed Energy Resources (DERs).
- Support environmental programs (Reduce, Reuse, and Recycle).

- SAFETY AND WELLNESS
  - Promote safety awareness for our associates and the community.
  - Strengthen NPEI's "Safety Culture"
  - Promote wellness initiatives with NPEI associates.

- CORPORATE LEADERSHIP
  - Provide our associates with the necessary skills to meet customer needs and expectations.
  - Maintain long-term financial viability.
  - Develop resources to promote the sustainability of our operations.
  - Maintain regulatory compliance.
  - Continue to build value for our Shareholders.

These strategic goals align themselves with 4 key criteria used in the prioritization of planned capital expenditures:

- Reliability / Performance
- Efficiency
- Safety
- Community Relations / Regulatory

This Distribution System Plan builds upon the Distribution System Plan (DSP) developed as part of the 2014 Distribution Rate Application. In particular, the 2014 Asset Condition Assessment (ACA) previously used to support NPEI's asset management strategies has been updated in 2019 by Kinectrics Inc. ("Kinectrics"). The ACA report provided by Kinectrics is entitled: "Distribution Asset Condition Report - 2018" and is included in Appendix of this document. The asset condition data used to support the Asset Condition Assessment were provided to Kinectrics for the following major asset categories:

- Power Transformers
- Large Pad-mounted Transformers
- Small Pad-Mounted Transformers
- Pole Top Transformers
- Poles
- Pad-Mounted Switchgear
- Underground Primary Cables
- Overhead Primary Conductor

NPEI monitors feeder performance through data collected by its Outage Management System. Feeder performance values are used in conjunction with asset health indices as key drivers for capital expenditure planning to identify feeders that require urgent attention.

The DSP also considers historical capital expenditure and potential external drivers which impact the mix and scope of capital investments. Capital investments for the period covered by this DSP are mapped according to the following project categories:

System Access: These are investments to support municipal development, regional development, and demand for new/upgraded connections. These include road relocation projects in partnership with land use authorities and expansions for customer connections or property development. One key driver that has been considered in this plan is the proposed development of the new South Niagara Hospital which is currently planned for construction during the forecast period of this DSP.

System Renewal: Investments categorized as system renewal are required to sustain existing operations maintaining an acceptable level of asset performance. System Renewal expenditures are based on the results of the 2019 Asset Condition Assessment report. The ACA report provides health indices for major asset categories which NPEI uses to prioritize asset replacements. In addition to the ACA, NPEI categorizes some of its programs as System Renewal based on identification of assets at end of life. An example of this is the kiosk replacement program where the holistic population of the asset base is at end of life.

System Service: These investments include upgrades and modifications to NPEI's distribution system to meet reliability expectations and provide future capacity. While these investments enhance NPEI's operational capabilities, they also typically result in distribution system loss reduction. The investments include deployment of new technologies to improve operational effectiveness.

General Plant: Investments in general plant support NPEI's capital expenditure plan. These investments are driven from the attached 2019 Fleet Assessment and 2019 IT Assessment.

A description of projects and programs associated with these categories is provided in greater detail in this document.

5.2.1.2 Overview of Customer Preferences and Expectations

Overall, NPEI's customers were supportive of its 2021-2025 draft plan as it was presented during the customer engagement process. In each of the three workbooks (Residential, Small Business and GS > 50 kW), the majority of customers surveyed indicated a preference for NPEI to either maintain the proposed rate increase to deliver a program that focuses on the priorities of its draft plan, or to improve service even if that means an increase that exceeds what is proposed in the draft plan.

In each case, however, the customer support for maintaining the proposed level of rate increase was greater than the customer support for improving service even if that means an increase that exceeds what is proposed in the draft plan.

Further, among Vulnerable Residential customers, a minority (29%) indicated that NPEI should keep increases below what is proposed in the draft plan even if that means reductions in service, compared to 11% of Residential customers overall.

In determining whether to adjust the overall level of spending proposed in its draft plan, NPEI has considered the following factors:

- Balancing customer preferences in general against the preferences expressed by the more vulnerable Residential customers.

- The resulting level of bill impacts to all customer classes.
- Internal resource constraints: whether or not an increase in the overall level of proposed capital projects or programs may require additional engineering or operations resources beyond NPEI's current staffing levels.
- Financial leverage: whether or not an increase in the overall level of proposed capital projects or programs may require NPEI to incur additional debt.

Based on the above considerations, NPEI has decided to maintain the overall proposed level of capital spending consistent with what was included in the draft plan.

In response to customer preferences on pacing of capital investments, NPEI has made adjustments to several specific capital programs, as detailed below.

In addition, if capital projects or programs that are planned during the 2021-2025 period need to be deferred, NPEI will incorporate customer preferences when selecting alternative projects to prioritize.

<u>Overhead Pole Replacement</u>

Among Residential customers, a plurality (47%) indicated a preference for an accelerated pace, while among Vulnerable Residential customers, a plurality (43%) indicated a preference for a slower pace than what was proposed in the draft plan.

Among Small Business Customers, a majority (56%) indicated a preference for an accelerated pace.

Of the GS>50 kW respondents, 15 of 32 indicated a preference for the pace that was included in the draft plan.

In considering the overall customer preferences from each rate class, as well as the specific preferences of the more vulnerable Residential customers, NPEI has not adjusted its proposed plan for Overhead Pole Replacement.

<u>Overhead Transformer Replacement</u>

Among Residential customers, a plurality (47%) indicated a preference for an accelerated pace, while among Vulnerable Residential customers, a plurality (38%) indicated a preference for a slower pace than what was proposed in the draft plan.

Among Small Business Customers, a majority (53%) indicated a preference for an accelerated pace.

Of the GS>50 kW respondents, 14 of 32 indicated a preference for an accelerated pace and 12 of 32 indicated a preference for what was included in the draft plan.

Although there is an apparent overall preference for an accelerated pace, Vulnerable Residential customers prefer a slower pace. In addition, the majority of Residential and GS>50 kW customers preferred either the draft plan or slower pace.

Therefore, NPEI has not adjusted its proposed plan for Overhead Transformer Replacement.

<u>Converting Outdated Underground Kiosk Transformers</u>

Among Residential customers, a majority (56%) indicated a preference for the pace that was included in the draft plan, while among Vulnerable Residential customers, a strong majority (73%) indicated a preference for either a reduced pace, or an even slower pace.

Among Small Business Customers, a majority (60%) indicated a preference for the pace that was included in the draft plan.

Of the GS>50 kW respondents, 21 of 32 indicated a preference for the pace that was included in the draft plan.

Although there is an apparent overall preference for the pace that was included in the draft plan, 73% of Vulnerable Residential exhibited a preference for a reduced pace or an even slower pace. In response, NPEI has reduced the proposed Conversion of Outdated Underground Kiosk Transformers program from replacing 11 units per year to 8 units per year, resulting in a reduction of $242,000 to this program.

Underground Cable Replacement

Among Residential customers, a majority (65%) indicated a preference for an accelerated pace, or an even further accelerated pace, while among Vulnerable Residential customers, a majority (58%) indicated a preference for an accelerated pace, or an even further accelerated pace

Among Small Business Customers, a majority (68%) indicated a preference for an accelerated pace, or an even further accelerated pace.

Of the GS>50 kW respondents, 16 of 32 indicated a preference for the pace that was included in the draft plan, 14 of 32 indicated a preference for an accelerated pace and 2 of 32 preferred a further accelerated pace.

In response to the overall preference amongst all customer types for an accelerated pace or an even further accelerated pace, NPEI has increased the level of its Underground Cable Replacement program. In order to maintain the overall level of proposed capital spending, NPEI has increased the proposed Underground Cable Replacement budget by $242,000, which corresponds to the reduction made to the Conversion of Outdated Underground Kiosk Transformers program. This proposed increase will allow NPEI to proactively replace approximately 0.3 km of additional underground cable annually.

Subdivision Underground Rehabilitation

Among Residential customers, a plurality (45%) indicated a preference for the pace that was included in the draft plan, while among Vulnerable Residential customers, a plurality (45%) indicated a preference for a slower pace.

Among Small Business Customers, a majority (52%) indicated a preference for the pace that was included in the draft plan.

Of the GS>50 kW respondents, 14 of 32 indicated a preference for a slower pace.

In considering the overall customer preferences from each rate class, as well as the more vulnerable Residential customers, NPEI has not adjusted its proposed plan for Subdivision Underground Rehabilitation.

Overhead Rebuilds

Among Residential customers, a narrow majority (50%) indicated a preference for the pace that was included in the draft plan, while among Vulnerable Residential customers, a plurality (39%) indicated a preference for the pace that was included in the draft plan.

Among Small Business Customers, a plurality (45%) indicated a preference for the pace that was included in the draft plan.

Of the GS>50 kW respondents, 19 of 32 indicated a preference for the pace that was included in the draft plan.

Due to agreement of overall customer preferences for the pace that was included in the draft plan, NPEI has not adjusted its proposed plan for Overhead Rebuilds.

Grid Modernization

Among Residential customers, a plurality (44%) indicated a preference for the pace that was included in the draft plan, and among Vulnerable Residential customers, a plurality (38%) also indicated a preference for the pace that was included in the draft plan.

Among Small Business Customers, an equal number (41%) indicated a preference for the pace that was included in the draft plan as those who indicated a preference for an accelerated pace.

Of the GS>50 kW respondents, 14 of 32 indicated a preference for the pace that was included in the draft plan and 12 of 32 indicated a preference for an accelerated pace.

Due to agreement of overall customer preferences for the pace that was included in the draft plan, NPEI has not adjusted its proposed plan for Grid Modernization.

5.2.1.3 Cost Savings Expected Over Forecast Period

The capital programs and projects identified over the forecast period are generally expected to result in improvement in reliability and operational efficiency, and distribution system losses reduction. Continuing to improve system reliability while maintaining asset integrity has been a key focus of NPEI’s historical capital expenditures. This focus has been confirmed by feedback obtained through customer surveys and will continue to drive programs and projects identified in the forecast period.

Improved reliability will result from NPEI's ability to quickly react and respond during contingencies. Many of the projects identified under the System Service category are designed to increase NPEI’s operational capability through the addition of feeder tie points and extension of main feeder infrastructure. Additionally, NPEI endeavours to implement technologies that enable remote response and automation to decrease overall response times during contingencies.

It is important to note that while the majority of NPEI’s capital expenditure focuses on system renewal, many of the projects within this category also contribute to improved reliability. Reconstruction of pole lines and underground facilities result in installations with increased capacity, improved sectionalizing capability, and the introduction of new technologies. New construction in residential areas are based on NPEI’s current standards which include covered conductor and insulated brackets in order to mitigate outages caused by tree or animal contact. Elimination of small step-down transformers removes a point of failure from the system while reducing the overall loss footprint on the distribution system.

NPEI has integrated its Geographical Information System (GIS) to the Distribution Engineering Simulation Software (DESS) package. The GIS and DESS software platforms contain a model of NPEI's entire distribution system allowing it to be used to support design. The DESS model also utilizes data from NPEI's operational data store (ODS) providing the tools to perform feeder optimization studies. These studies support design and operation of the distribution system resulting in a reduction of system losses and support of DER connections.

NPEI has also successfully integrated its advanced meter infrastructure (AMI) to the InService Outage Management System (OMS). Real time reporting of outage and restoration notifications from the meter to the OMS provides instantaneous prediction of failed devices on the distribution system resulting in an improvement in response and restoration time. NPEI is building on its successes by introducing grid modernization strategies into station design and communication network deployment to achieve real time input of device status into the OMS. This will provide NPEI with real time operating control of the network and result in reduced travel time for crews for tasks such as protection feature blocking.

NPEI is an active member of the Utilities Standards Forum (USF) . The USF is an organization consisting of 53 Ontario LDCs which pool resources and ideas in the areas of Engineering and Operations, Regulatory and IT program management. NPEI was one of the founding members and continues to be an active member on many of the USF committees. By pooling resources and working collectively, member LDCs realize cost savings in areas such as development of design standards, cyber security protocols and training.

NPEI is an active member of the GridSmartCity Cooperative. This Cooperative is made up of thirty four partner organizations including Ontario LDCs, commercial entities and academia. At present, there are fourteen member LDCs, representing over 737,000 customers in Ontario. Members have come together to share resources and insights in several key areas to help members run smarter companies and advance innovation, reliability and efficiencies across Ontario's electricity grid. Since being established in 2009, the GridSmartCity Cooperative has achieved the following:

- Established a formal cooperative material standardization and purchasing function to consolidate volumes and reduce inventory costs.
- Realized $1.2M in cumulative savings in the volume purchase of poles, cable and transformers.

5.2.1.4 Distribution System Planning Period

NPEI's DSP has been prepared for the following period:

Historical Period				Bridge Year	Test Year	Forecast Period			
2016	2017	2018	2019	2020	2021	2022	2023	2024	2025

5.2.1.5 Vintage of Information

All asset inspection/condition assessment data is current per the inspection intervals described in the Asset Management Process. Unless otherwise noted, all information contained in the DSP is current as of December 31, 2018.

5.2.1.6 Important Changes to Asset Management Process

NPEI has implemented technological improvements such as utilizing tablets for field inspection data gathering, however, there have not been any significant changes to the overall Asset Management Process since the previous DSP submission.

5.2.1.7 Supporting Studies and Inputs

Several key studies and input documents support NPEI's asset management process and capital expenditure plan. The documents are included in the appendix and their utilization is further explained in this DSP. The supporting documents are as follows:

- IRRP- Integrated Regional Resource Planning - Appendix B
- RIP-Regional Infrastructure Planning – Appendix C
- 2019 REG Investment Plan – Appendix D
- 2019 NPEI Customer Engagement Plan - Appendix E
- 2018 Asset Condition Assessment (ACA) - Appendix F
- 2019 Grid Modernization Strategy - Appendix G
- 2019 Feeder Reliability Assessment - Appendix H
- 2019 IT Assessment

5.2.1.8 Grid Modernization, Distributed Energy Resources & Climate Change Adaptation

NPEI has many ongoing and proposed projects to address grid modernization, DER integration and climate change adaptation. Completing these activities will improve service and quality to our customers and aligns with some of the goals and objectives identified in Ontario's Long-Term Energy Plan 2017: Delivering Fairness and Choice (LTEP). NPEI incorporates these considerations in rebuild projects as well as when planning for system expansions. NPEI is actively pursuing the following actions:

Communications Network – Communications networks represent the backbone of smart grid systems. NPEI to date has built and deployed a wireless point-to-multi-point network (WiMAX network) utilizing an Industry Canada allocated 1800-1830 MHz bandwidth. To date, 90% of the back-bone network is in service, this includes three (3) towers and nine (9) base stations. This activity aligns with the LTEP goal of "Innovating to meet the Future".

Installation of automated switches (reclosers) – NPEI has eliminated all archaic electromechanical reclosers and installed electronically controlled vacuum reclosers. These devices included integrated smart relays for control and monitoring purposes with provision for communication. These are expected to improve the efficiency of outage restoration work as remote monitoring and control will eliminate the need to dispatch a crew to physically operate the device. This activity aligns with the LTEP goal of "improving Value and Performance for Consumers".

Storm Hardening – NPEI utilizes several proven storm and weather proofing techniques when designing new and rebuild installations. Stainless steel equipment is utilized where it may be exposed to winter road salt. Dead end and equipment poles are increased in class size to provide additional strength. Poly covered tree wire is used in overhead installations where tree contact is probable, to minimize outages. Insulated equipment brackets and animal guards are used wherever practicable. This activity aligns with the LTEP goals of "Ensuring a Resilient Energy Supply" and "Improving Value and Performance for Consumers".

Installation of Line Sensors / Fault Indicators - NPEI plans the installation of smart Line Fault Indicators at key intersections within our system. These devices are installed on 3 phase lines, typically at tie points along main feeders. The endpoint devices can be connected into our SCADA system via our WiMAX network. The devices will help NPEI in two major areas:

a. Line Fault Detection:

In certain areas within our territory when an outage occurs, it can be difficult to locate the problem without patrolling the lines. These devices will reduce the down time and assist our crews in locating faults.

b. Line Current Monitoring:

As the devices will be tied into our SCADA monitoring system, it will allow our Control Room to monitor line current in real time at mid points along a Feeder. Traditionally, live Feeder monitoring was only achievable at Substation breakers and mid stream reclosers. Having this new data will help validate our system model for Load Flow studies and help ensure loads are balanced between phases.

This activity aligns with the LTEP goal of “Innovating to meet the Future”.

5.2.2 Coordinated Planning with Third Parties

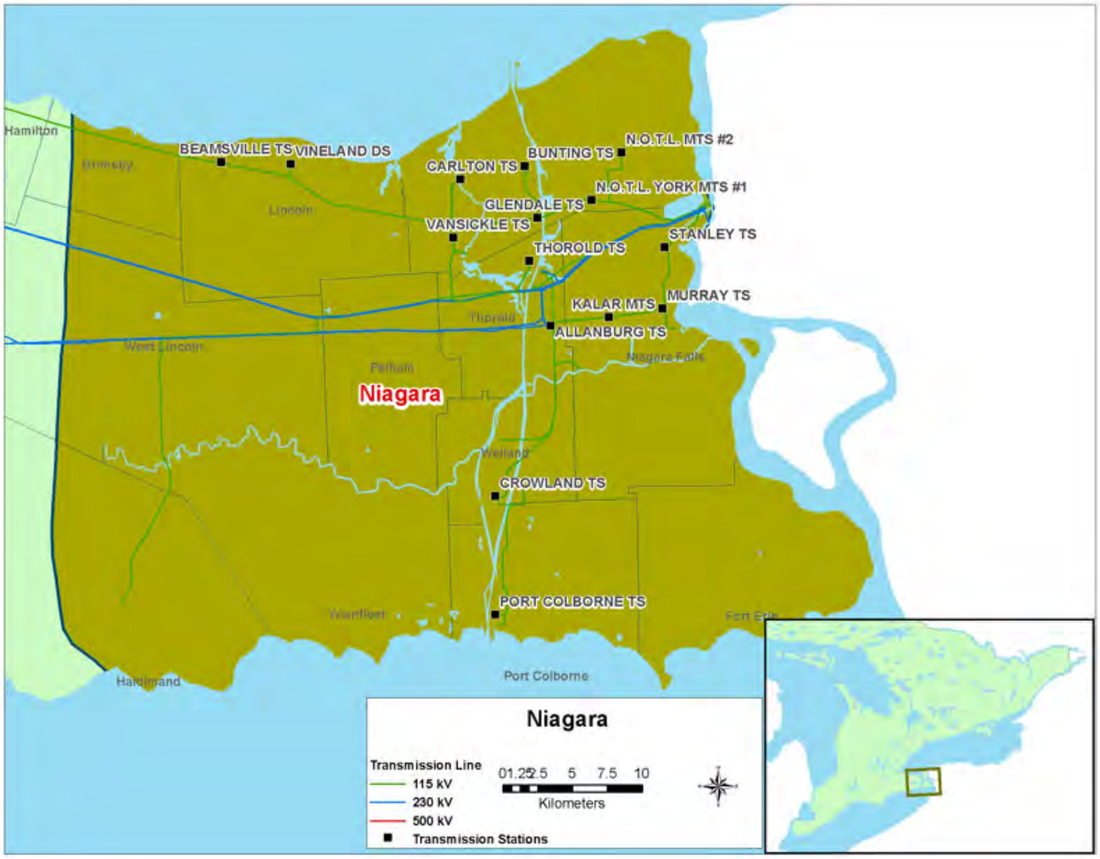
The following outlines how NPEI has met the OEB’s expectations for coordinating infrastructure planning with customers, the transmitter, other distributors, the Ontario Power Authority, and other third parties. As part of the renewed regulatory framework, the OEB has expanded the Cost of Service Distribution Rate Application filing with new requirements for a formalized DSP to demonstrate and document NPEI's coordinated planning and formal engagement with the following stakeholders and processes:

- Regional Planning with the IESO
- Regional Infrastructure Planning (RIP) with Hydro One Networks Inc. (HONI)
- Renewable Energy Planning with the IESO
- Neighbouring LDCs
- Customer and Industry Stakeholder Engagement
- Municipality Consultations

5.2.2.1 Regional Planning with IESO

On March 28, 2017, NPEI received the Regional Infrastructure Planning report for Group 3 from Hydro One. The Needs Assessment was started on October 15, 2015 and concluded on April 30, 2016 covering the 10 year period through 2025. The local transmitter (Hydro One) has completed the Needs Assessment for this planning region and found that there were no needs that required regional coordination, completing the regional planning process for this planning cycle.

NPEI is part of the Niagara Region in the Southern Ontario area:



<u>**Figure 5- 1: Map of Niagara Planning Region (Source: IESO)**</u>

5.2.2.2 Regional Infrastructure Planning (RIP) with HONI

On March 28, 2017, NPEI received the Regional Infrastructure Planning report for Group 3 from Hydro One. The report / Needs Assessment was started on October 15, 2015 and concluded on April 30, 2016 covering the 10 year period through 2025. Based on the findings of the Needs Assessment, the study team recommended that the thermal overloading of 115kV circuit Q4N should be further assessed as part of the Local Plan. No further regional coordination or planning was required. The next cycle of Regional Infrastructure Planning is scheduled to begin in 2021.

5.2.2.3 Renewable Energy Generation Planning with the IESO

NPEI has developed a Renewable Energy Generation (REG) Investment Plan to provide to the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO). The purpose of the plan is to review NPEI's ability to connect Distributed Energy Resources (DER's) to its distribution system and identify any investments required to accommodate these connections over the next 5 years. NPEI does not anticipate any specific investment needs over the next 5 years related to DER's. NPEI submitted a copy of the REG Investment Plan to the IESO on October 18th, 2019 for their review and comment. The IESO confirmed via email on October 23rd, 2019 that "In the case where a distributor has no REG investments during the 5-year Distribution System Plan (DSP) period no letter from the IESO is required."

5.2.2.4 Neighbouring and Other LDCs

On July 4th, 2019, NPEI attended a local LDC meeting hosted by HONI. This meeting was attended by Alectra, CNPI, GPI, NPEI and Welland Hydro. The agenda for the meeting was to review HONI's Regional Planning Process and also for all of the neighbouring LDCs to discuss upcoming major projects, forecasted load growth and any potential issues in the Niagara Region related to electricity capacity. Minutes of the meeting are included in Appendix B.

NPEI has a strategic partnership with neighbouring utilities known as the Niagara Erie Public Power Alliance (NEPPA). The NEPPA group shared infrastructure during the Smart Meter implementation for the AMI, where towers and base stations to establish the communication network were shared between the seven member utilities:

- Niagara Peninsula Energy Inc.
- Fortis Inc.(Canadian Niagara Power)
- Grimsby Power Inc.
- Haldimand County Hydro Inc.
- Niagara-On-The-Lake Hydro Inc.
- Norfolk Power Inc.
- Welland Hydro Electric System Corp.

NPEI is also a member of the GridSmartCity Cooperative of 14 LDCs. The Cooperative bridges the need for innovation and infrastructure renewal, with the benefits of collaboration and cost efficiency. Operating within a formalized structure, and as a legal cooperative entity, our LDC members share resources, insights and systems that help run smarter companies, while advancing innovation, reliability and efficiency across Ontario's electricity grid. Our Cooperative is an extension of GridSmartCity, one of Ontario's leading smart grid consortiums.

- Brantford Power
- Burlington Hydro
- Energy +
- Entegrus
- Enwin
- Essex Powerlines
- Halton Hills Hydro
- Kingston Hydro
- Kitchener Wilmot Hydro
- Milton Hydro
- Niagara Peninsula Energy inc.
- Oakville Hydro
- Waterloo North Hydro Inc.
- Welland Hydro

5.2.2.5 Customer and Stakeholder Engagement

Customer service is a core business function of NPEI, and commitment to excellence is a major focus within its day to day operations. Several options exist in which Customers can engage NPEI staff with concerns or questions they need addressed, whether directly or indirectly. Since the implementation of

Smart Meter Technology, the Customers supply NPEI with crucial operational information. In the last few years, NPEI has made major investments in systems to aid staff in providing state of the art Customers service. The most noteworthy, is implementation of the Outage Management System (OMS). The OMS is able to poll Smart Meters within its Service Territory and display the meters reporting an outage. Depending upon the number, the OMS compiles the information and predicts the possible point of failure. This provides operators with accurate information for the efficient dispatch of crews for timely power restoration, regardless of the size of the event.

During normal working hours NPEI has staff available to address customer requests, as related to billing, new service requests, REG inquiries, outage reporting, or project inquiries. Another option is the NPEI website, providing a means for Customers to leave comments or questions to appropriate staff, during or after normal working hours. Requests are reviewed by a manager or supervisor and distributed to appropriate Staff for follow-up. NPEI has provided the means for their Customers to interact, as conveniently as possible. NPEI also leverages social media outlets such as Twitter and Facebook to provide notification as another form of Customer engagement.

NPEI engages Customers prior to implementation of Major Projects within its Service Territory. The Technician managing the project delivers construction notices, to each customer and business affected, outlining project scope, and contact information. This typically occurs three weeks prior to the start date. Questions or concerns are addressed where practical, and layout adjustments are implemented. In certain circumstances, NPEI will host Town hall meetings when substantial civil works could impact Customers' property or access.

NPEI participates with their municipal partners and fellow utility providers, in monthly Public Utility Committee (PUC) Meetings. Short and long term planning goals, of the various agencies, are shared in the group to aid in efficient planning and coordination between the agencies, as required. Participants include The Regional Municipality of Niagara, the City of Niagara Falls, the Township of Lincoln, the Township of West Lincoln, the Town of Fonthill, the Ministry of Transportation, The Ministry of Labour, Cogeco Cable, Enbridge Gas, Bell Telephone, and the Niagara Parks Commission. Minutes are kept by the various municipalities and are made Public. Relevant information is shared with appropriate staff to aid in planning, budgeting and scheduling.

5.2.2.6 Municipality Consultations

NPEI maintains a close relationship with the Municipalities that it serves and their respective Development and Planning staff. Discussions include planned activities that can affect budgets, BIA/Municipality redevelopment plans and scheduling/coordination on a per project basis and during construction season.

The Niagara Region has been included in the "A Place to Grow" growth plan for the Greater Golden Horseshoe plan by the province of Ontario. The province has set a growth forecast of 610,000 people for the Niagara Region by 2041. This is an increase of 168,000 people between 2011 (the last Census year) and 2041. In response to this forecast, the Niagara Region has initiated their own "Niagara 2041 Growth Strategy". The projected yearly growth rates within NPEI's service territory for the forecast period of this DSP are: 1.11% for Lincoln, 1.41% for Niagara Falls, 1.55% for Fonthill (Pelham) and 2.83% for West Lincoln.

MCR Strategic Growth Option Forecast Total Population by Local Municipality, 2016 -2041											
Municipality	Total Population Including Net Undercoverage									2016 - 2041	
	2001	2006	2011	2016	2021	2026	2031	2036	2041	Net Change	Compound Annual Growth Rate
Fort Erie	29,120	30,960	30,760	31,030	32,310	34,720	37,780	41,220	43,940	12,910	1.40%
Grimsby	22,030	24,760	26,000	27,580	29,430	31,400	33,200	35,140	37,150	9,570	1.20%
Lincoln	21,320	22,460	23,080	23,950	24,990	26,230	28,060	30,030	31,590	7,640	1.11%
Niagara Falls	81,550	85,040	85,200	87,740	92,830	99,990	108,770	117,670	124,580	36,840	1.41%
Niagara-on-the-Lake	14,320	15,090	15,810	17,950	19,750	21,420	22,850	24,700	26,580	8,630	1.58%
Pelham	15,790	16,710	17,040	17,190	17,900	19,410	21,560	23,720	25,260	8,070	1.55%
Port Colborne	19,080	19,240	18,910	18,510	18,600	19,210	20,080	21,050	21,820	3,310	0.66%
St. Catharines	133,660	136,570	134,890	133,820	136,930	142,560	150,590	160,040	167,480	33,660	0.90%
Thorold	18,670	18,880	18,410	18,790	19,680	21,500	23,850	26,470	28,470	9,680	1.68%
Wainfleet	6,470	6,830	6,520	6,540	6,590	6,760	6,990	7,260	7,480	940	0.54%
Welland	50,080	52,080	51,980	52,550	54,130	56,540	59,600	63,160	66,180	13,630	0.93%
West Lincoln	12,690	13,620	14,200	14,670	16,170	18,930	22,630	26,530	29,460	14,790	2.83%
Niagara Region	**424,780**	**442,240**	**442,800**	**450,320**	**469,310**	**498,670**	**535,960**	**576,990**	**609,990**	**159,670**	**1.22%**

5.2.3 Performance Measurement for Continuous Improvement

NPEI monitors a number of performance based metrics, including those mandated by the OEB, as inputs to the asset management and capital expenditure planning processes. Monitoring system performance provides NPEI with the information required to appropriately adjust its plans or to identify remedial steps to ensure that distribution assets remain in service for the duration of their design lifespan and can serve under peak demand conditions. The metrics provide an essential feedback mechanism to ensure that NPEI is maintaining alignment with NPEI's strategic business objectives.

These measures can be divided into three groups:

1) customer oriented performance;
2) cost efficiency and effectiveness;
3) asset/system performance

NPEI's current performance state is represented by NPEI's official scorecard results as published by OEB. The scorecard is designed to track and show NPEI's performance results over time and helps to clearly benchmark its performance and improvement against other utilities and best practices. The scorecard includes traditional metrics for assessing services, such as frequency of power outages and costs per customer. NPEI's OEB scorecard is shown in Appendix I.

The following sections address performance metrics as published by the OEB in the performance scorecard and with additional performance metrics identified in OEB's Rate Filing Requirements.

5.2.3.1 Customer Oriented Performance

5.2.3.1.1 Service Quality

5.2.3.1.1.1 Methods and Measurements

NPEI measures and reports on an annual basis on each of the service quality requirements set out in the Distribution System Code (DSC). Failure to meet minimum service quality targets would result in measures being taken to realign performance with DSC service quality standards. Service Quality measures include the following major measures: New Residential/Small Business Services Connected on Time, Scheduled Appointments Met on Time and Telephone Calls Answered on Time. Additional sub-measures are tracked as part of the DSC requirements. All these measures are self explanatory in nature and relate to NPEI's commitment to providing high quality connection and customer services. NPEI is committed to meeting and exceeding all targets found in the Service Quality performance measure group.

5.2.3.1.1.2 Historical Performance

NPEI has consistently exceeded the OEB targets for service quality as part of the customer focus section of the OEB scorecard. NPEI's customer service representatives answer a varying number of phone calls per year within the 30 second window prescribed by the OEB. The overall answer rate is well above the industry targets and is indicative of NPEI's dedication to customer service. Table 5-1 presents the measures and sub-measures for tracking NPEI's performance in the service quality category.

Table 5- 1: Performance measures – Service quality

Measure	Sub-Measure	2015	2016	2017	2018	2019
New Residential / Small Business Services Connected on Time		91.4%	92.7%	91.5%	93.3%	
	Low Voltage Connections	91.4%	92.7%	91.5%	93.3%	
	High Voltage Connections	94.5%	100.0%	100.0%	90.7%	100%
	Reconnection Performance Standards	100.0%	100.0%	100.0%	100.0%	
Telephone Calls Answered on Time		82.7%	83.0%	88.0%	85.9%	
	Telephone Accessibility	82.7%	83.0%	88.0%	85.9%	
	Telephone Call Abandon Rate	1.0%	0.9%	0.9%	1.3%	
Scheduled Appointments Met on Time		95.7%	99.8%	98.3%	98.9%	
	Appointments Met	95.7%	99.8%	98.3%	98.9%	
	Appointment Scheduling	100.0%	100.0%	100.0%	100.0%	
	Rescheduling Missed Appointments	100.0%	100.0%	100.0%	100.0%	
Written Response to Enquiries		100.0%	100.0%	93.1%	86.3%	88.87
Emergency Urban Response		91.5%	97.1%	97.1%	100.0%	
Emergency Rural Response		83.7%	93.5%	100.0%	100.0%	

5.2.3.1.2 Customer Satisfaction

5.2.3.1.2.1 Methods and Measurements

NPEI measures and reports on customer Satisfaction measures which include: First Contact Resolution, Billing Accuracy and Customer Satisfaction Survey Results. NPEI uses the OEB Targets for these measures and relies on their staff to meet these targets. Additionally, NPEI tracks Bill Impacts on its customers yearly.

Bill Impacts

The majority of a customer's bill is due to factors (i.e. generation, transmission, global adjustment, etc.) outside the control of the LDC. Notwithstanding that, surveys continue to indicate that it is the overall cost of the bill, not the individual components, that are of concern to the customer. NPEI considers the short- and long-term customer bill impacts as part of the asset management process, and bill impact mitigation is a consideration in investment planning decisions. Where possible, NPEI's forward looking asset management plans and programs are structured to smooth customer bill impacts over the years. This is especially evident in programs where the utility has a greater degree of control over project pacing and prioritization, such as asset refurbishment/replacement, where risk and rate mitigation inputs are considerations to program scheduling. While most of the investment scheduling can be smoothed, certain capital expenditures are lumpy in nature and these may result in expenditure volatility in a specific year.

NPEI's target for this measure is for rate impacts in residential and general service classes to remain within OEB rate mitigation guidelines.

Customer Satisfaction Survey

NPEI undertakes a customer satisfaction survey on a biannual basis to obtain feedback on the overall value of service offered to customers. The latest such survey took place in 2019. Customers (residential and commercial) are engaged to provide high level feedback on their perceptions of NPEI's performance and where they think NPEI could improve service. This information is extremely useful to help guide future investment planning that will maintain or improve customer satisfaction.

NPEI's target is to be within a (+/-) 5% range of previous survey scores for the following survey metrics:

- Customer Care
- Company Image
- Management Operations
- Customer Centric Engagement Index
- Customer Experience Performance rating

5.2.3.1.2.2 Historical Performance

NPEI has consistently exceeded the OEB targets for service quality as part of the customer focus section of the OEB scorecard. NPEI places a strong emphasis on being the "Local Utility" and involving our customers in discussions to understand their preferences and concerns.

Table 5- 2: Performance Measures – Customer satisfaction

Measure	2015	2016	2017	2018	2019
First Contact Resolution	94%	94%	92%	91%	
Billing Accuracy	99.28%	99.74%	99.46%	99.06%	
Customer Satisfaction Survey Results	87%	86%	86%	95%	95%

Bill Impacts

NPEI rebased its 2015 rates through a cost of service application in 2014. In subsequent years, Price Cap IRM applications were filed resulting in the approval of index-based adjustments to distribution rates. The annual distribution rate impacts through the historical period are shown in the table below:

Table 5- 3: Performance Measure – Bill impacts (rate adjustment impacts)

Class	2016	2017	2018	2019	2020
	Price Cap IR	Price Cap IR	Price Cap IR	Price Cap IR	Price Cap IR
Residential	1.80%	1.60%	0.90%	1.20%	1.70%
GS<50	1.80%	1.60%	0.90%	1.20%	1.70%
GS>50	1.80%	1.60%	0.90%	1.20%	1.70%
Sentinel Lighting	1.80%	1.60%	0.90%	1.20%	1.70%
Street Lighting	1.80%	1.60%	0.90%	1.20%	1.70%
USL	1.80%	1.60%	0.90%	1.20%	1.70%

Bill impact considerations are a key driver of NPEI's DSP development. The levelized investment plan reflected in the DSP contributes to smoothing customer bill impacts over the period of the plan and in NPEI's assessment is reasonable (within OEB mitigation guidelines). Furthermore, rate mitigation has been taken into consideration in the development of the DSP and NPEI's capital expenditure planning process through the customer engagement and feedback. The table below shows the proposed 2021 bill impact. The bill impact for 2021 is higher than previous years because of the nature of rate setting whereby during the cost of service year (2021) previous expenditures in capital are "trued-up" to set a new rate base. The next four years (2022-2025) will see bill impacts limited to the rate of inflation less a stretch factor that is approved by the Board for adjusting rates that are set using the Incentive Rate Mechanism (IRM) method.

Table 5- 4: Proposed 2021 Bill impacts (rate adjustment impacts)

Customer Class	2021 Bill Impact
Residential	
GS<50	
GS>50	
Street Lighting	
USL	

Customer survey

The customer survey results over the historical period are shown in the table below:

Table 5- 5: 2015 - 2019 Customer survey results

Survey Sub-Measure	2015	2017	2019
Customer Care	B	B	A
Company Image	A	A	A
Management Operations	A	A	A+
Customer Centric Engagement Index (CCEI)	78%	81%	87%
Customer Experience Performance rating (CEPr)	82%	83%	88%

The survey results indicate NPEI's customer service, care, and experience is good and has steadily been improving in all categories.

From 2015 through 2019, NPEI scored higher than National and Ontario benchmarks in all performance categories.

The CCEI and CEPr indexes, introduced in 2013, provide specific feedback on customer interaction perceptions and their engagement connection with the NPEI brand. Results have generally been consistently averaging in the mid-eighty percentile region over the historical period. NPEI's performance in this area exceeds both National and Ontario utility performance averages.

NPEI conducts customer satisfaction surveys on a biannual basis. Surveys show that the customers are very satisfied with NPEI's performance. NPEI reviews the survey results to determine if adjustments to corporate programs and strategies are warranted. Any significant change to program/strategies would affect the DSP. In general, customer attitudes and preferences (i.e. satisfaction with existing reliability levels) obtained from survey information has been a consideration in the development of the DSP and NPEI's asset management and capital expenditure planning process.

5.2.3.1.3 Reliability Performance

5.2.3.1.3.1 Methods and Measurements

NPEI monitors system reliability indices SAIDI, SAIFI, and CAIDI on a monthly basis. NPEI's outage management system (OMS) is the source of information for the 3 indices. Outage events are determined by the OMS based on the input of smart meter outage alarms and customer calls. The input of smart meter alarms provide a reliable start time for outage events as opposed to methods employed previously that relied on a customer's call. Upon receipt of a predicted outage, NPEI control room operators immediately dispatch field staff for investigation. Following restoration, crews identify the cause of the outage and restoration time on field based mobile devices. The restore time is compared to the restore notification from real time smart meter data and updated by NPEI operators. This process ensures the utmost accuracy in customer count, outage duration, and outage cause as related to service reliability indices.

Standard reports from NPEI's outage management system are available such that the overall service reliability indices can be summarized monthly. The indices are also summarized at the feeder level. Analysis of the indices allow NPEI to measure the success of operational and maintenance activities as well as whether capital expenditures in positively impacting system performance.

As required by the Ontario Energy Board's Electricity Reporting and Record Keeping requirements, the following indices are tracked and reported:

- SAIDI - System Average Interruption Duration Index:

$$SAIDI = \frac{Total\ Customer\ Hours\ of\ Interruption}{Average\ Number\ of\ Customers\ Served}$$

- SAIFI - System Average Interruption Frequency Index:

$$SAFI = \frac{Total\ Customer\ Interruptions}{Average\ Number\ of\ Customers\ Served}$$

- CAIDI - Customer Average Interruption Duration Index:

$$CAIDI = \frac{SAIDI}{SAIFI}$$

When a pattern of recurring failures emerges, the Engineering Department investigates and develops a strategy for improving reliability. Surveys and day to day customer feedback indicate that service reliability is a high priority for our customers. The same surveys and customer feedback also indicate that NPEI's customers generally are pleased with the level of reliability and power quality that is provided. NPEI continues to work proactively to monitor the power quality to ensure it does not adversely affect the customers in the service area. The OEB scorecard target for SAIDI, SAIFI are used as default targets for reliability performance expectations in the current year.

Feeder Performance Indices

With the implementation of an outage management system that leverages AMI data for outage and restoration notification messages, NPEI is able to provide an accurate depiction of feeder performance.

The feeder reliability indices are reviewed annually to identify year over year trending and identify poor performance. Feeders identified as having recurring poor performance levels, that are not attributed to an externally driven event, are analyzed to determine potential improvement measures. The feeder reliability indices, as well as the analysis of the worst feeders, are shown in Appendix H.

5.2.3.1.3.2 Historical Performance

Reliability Performance Metrics

The tables below indicate the monthly trend of SAIDI from 2015 to 2019.

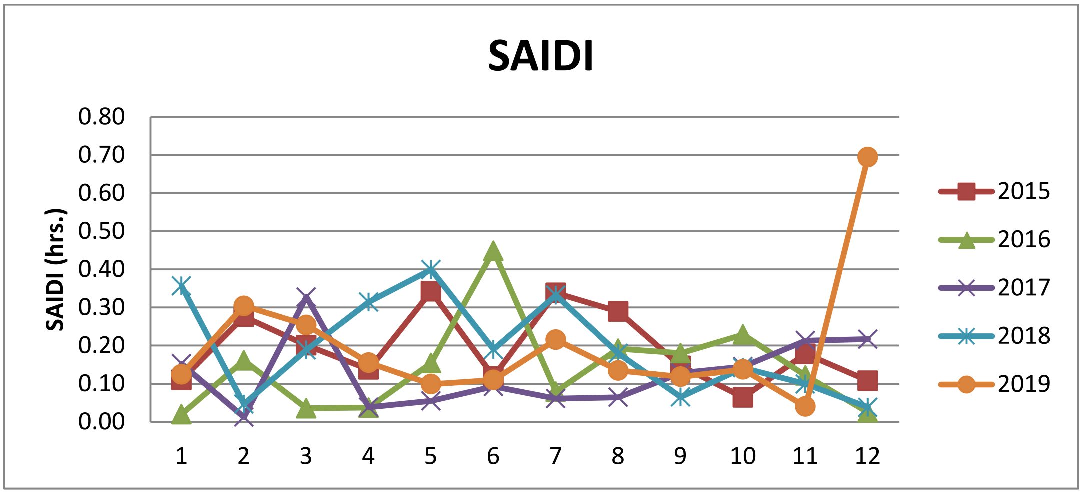


Figure 5- 2: Monthly Trend of SAIDI from 2015 to 2019

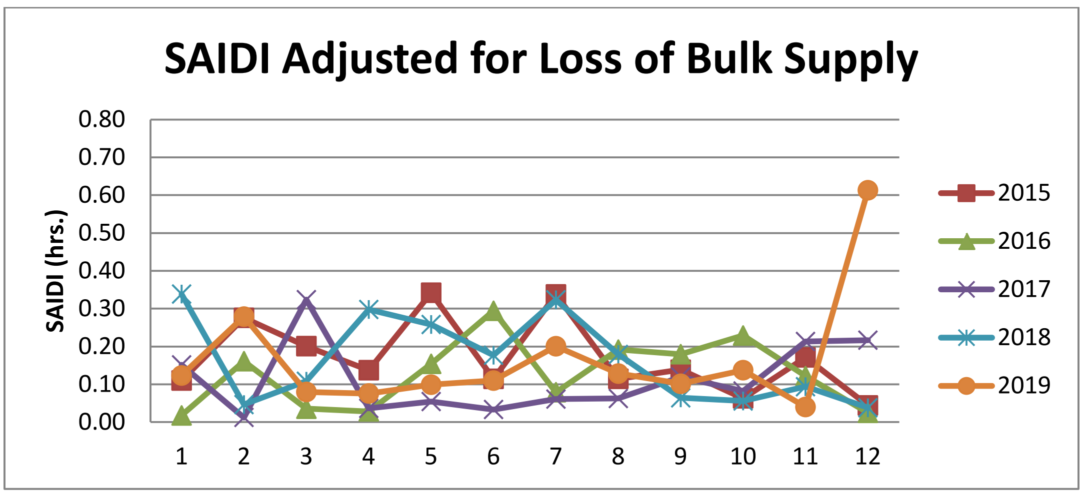


Figure 5- 3: Monthly Trend of SAIDI from 2015 to 2019 (Excluding Loss of Supply)

Additionally, the year to year trend of SAIDI is depicted in the tables below.

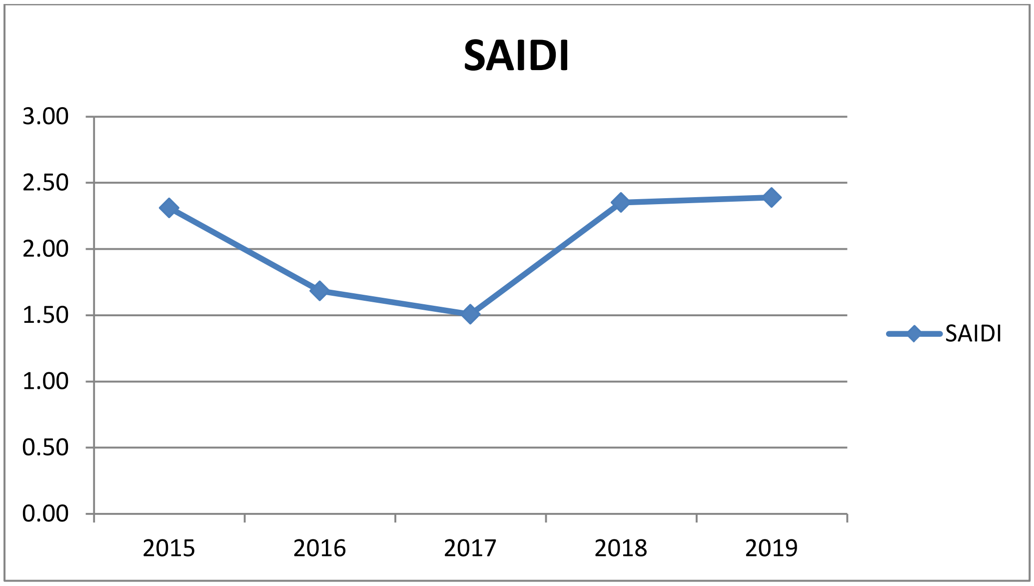


Figure 5- 4: Annual Trend of SAIDI from 2015 to 2019

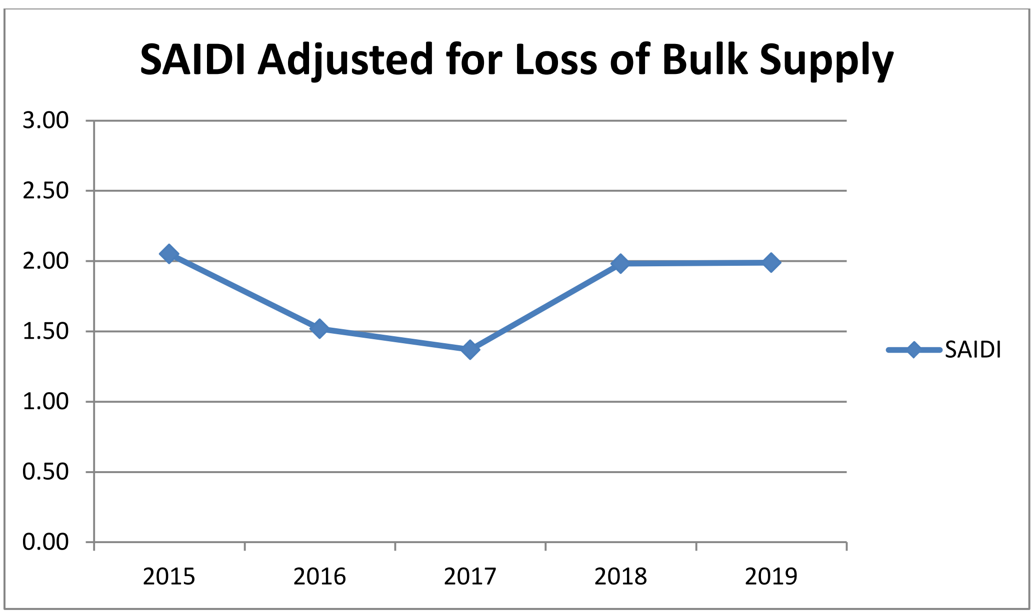


Figure 5- 5: Annual Trend of SAIDI from 2015 to 2019 (Excluding Loss of Supply)

The tables indicate that SAIDI has been trending relatively consistently over the historical period.

The table below indicate the monthly trend of SAIFI from 2015 to 2019:

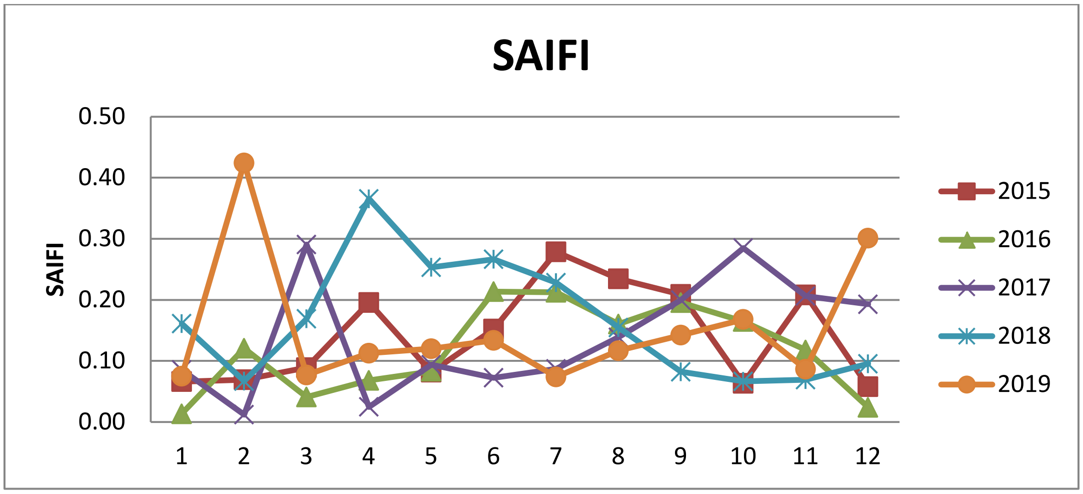


Figure 5- 6: Monthly Trend of SAIFI from 2015 to 2019

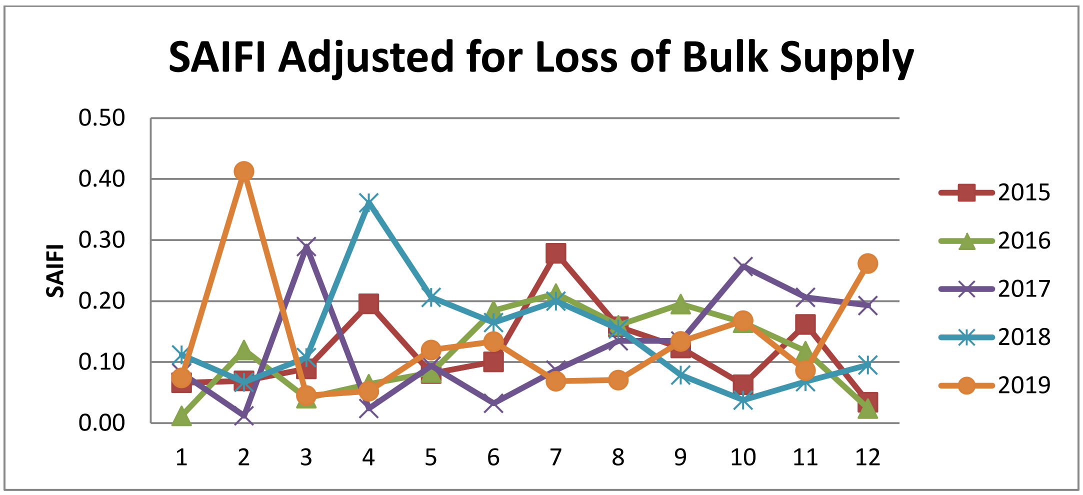


Figure 5- 7: Monthly Trend of SAIFI from 2015 to 2019 (Excluding Loss of Supply)

Additionally, the year to year trend of SAIFI is depicted in the following tables.

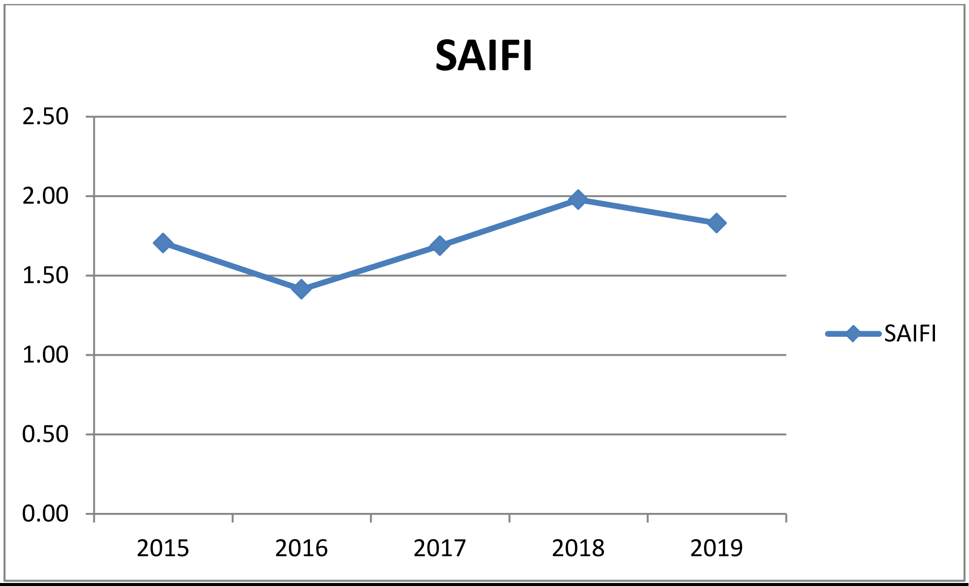


Figure 5- 8: Annual Trend of SAIFI from 2015 to 2019

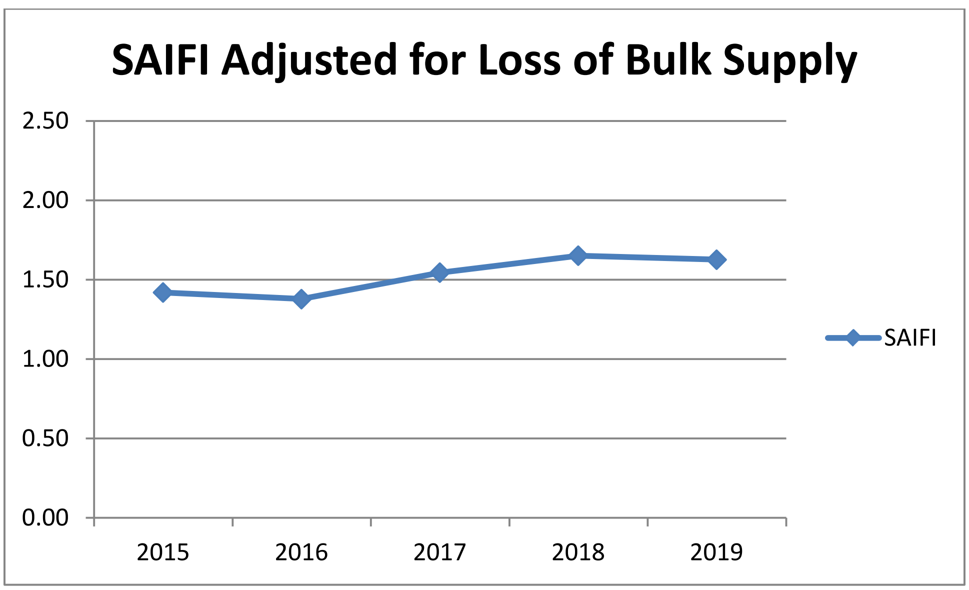


Figure 5- 9: Annual Trend of SAIFI from 2014 to 2019 (Excluding Loss of Supply)

The following tables indicate the monthly trend of CAIDI from 2015 to 2019:

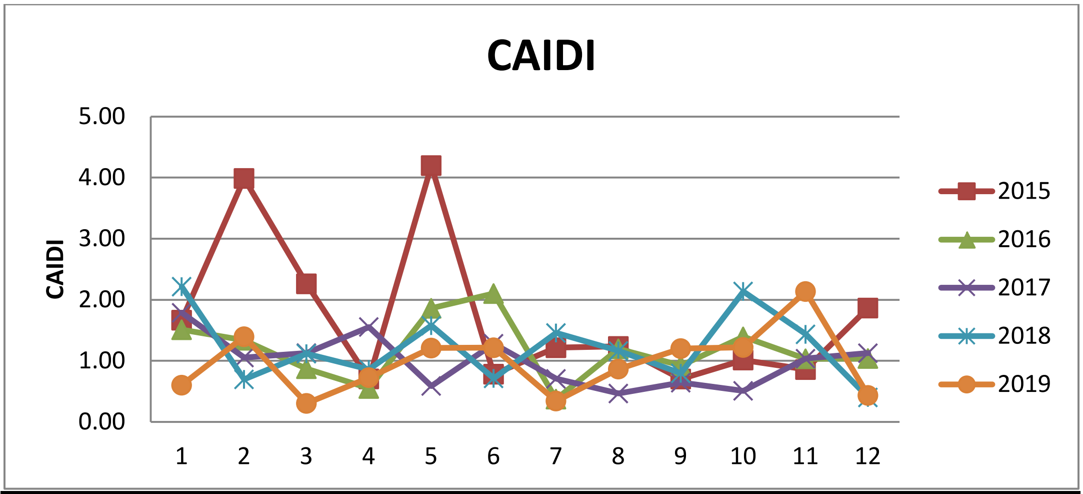


Figure 5- 10: Monthly Trend of CAIDI from 2015 to 2019

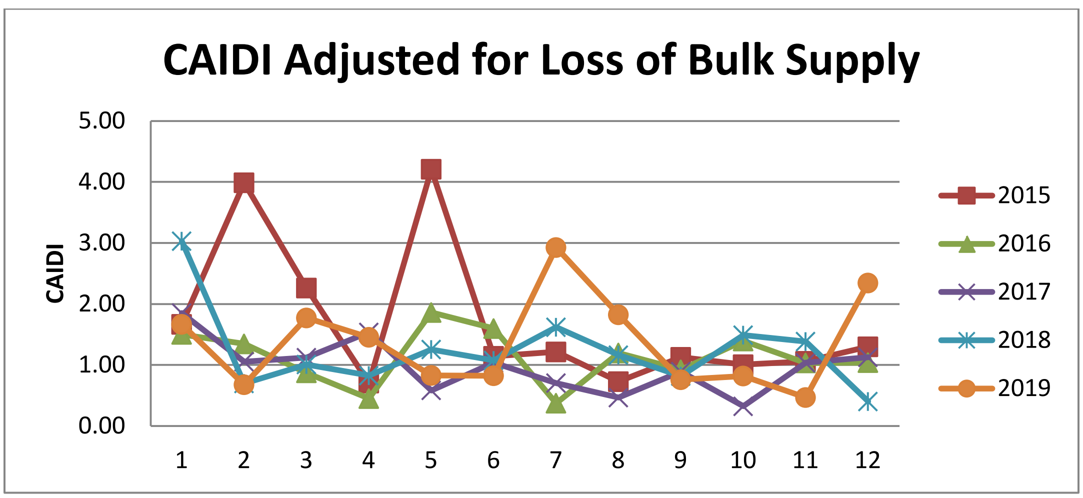


Figure 5- 11: Monthly Trend of CAIDI from 2015 to 2019 (Excluding Loss of Supply)

Additionally, the year to year trend of CAIDI is depicted in the tables below.

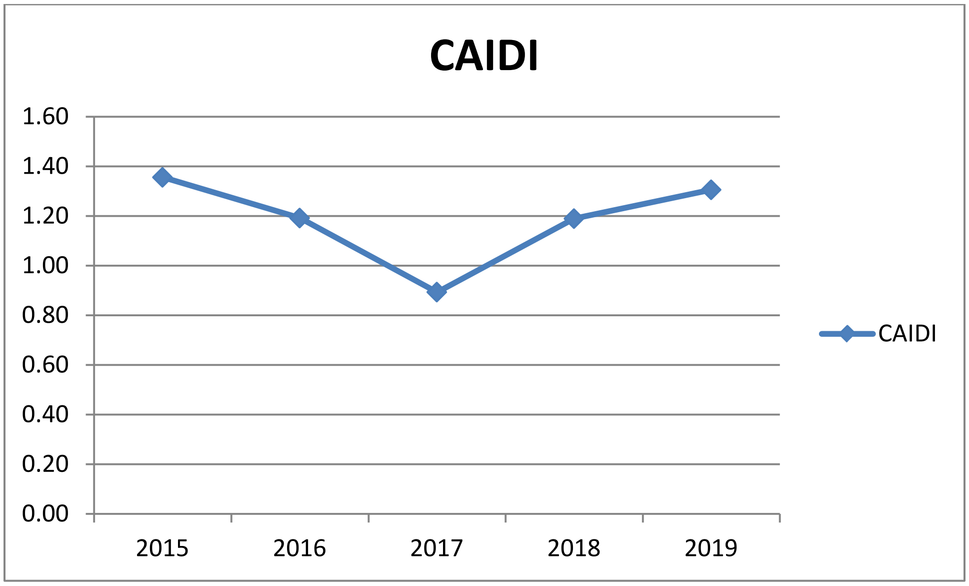


Figure 5- 12: Annual Trend of CAIDI from 2015 to 2019

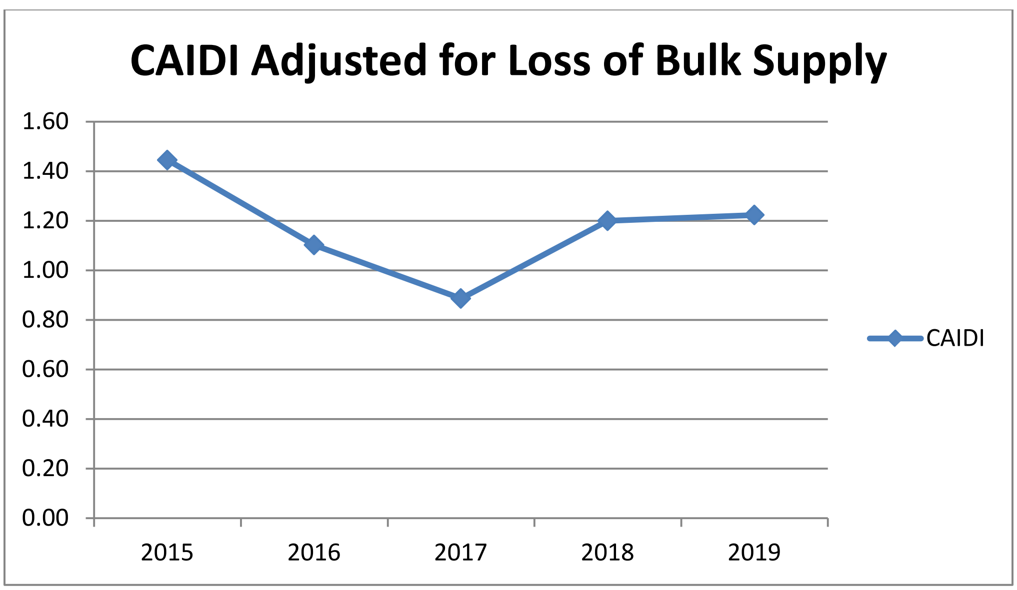


Figure 5- 13: Annual Trend of CAIDI from 2015 to 2019 (Excluding Loss of Supply)

Significant Weather Events

Customer interruptions are reported by Cause Code, as set out in Section 2.1.4.2.5 of the RRR. The SAIDI and SAIFI indices that are reported on the annual *Scorecards of Electricity Distributors* exclude customer interruptions that are due to Loss of Supply and Major Events.

Table 5.6 below shows NPEI's System Reliability Indicators for the 2015-2019 historical years. NPEI confirms that the data presented in Table 5-6 is consistent with data that has been reported, or will be reported, on NPEI's annual *Scorecard of Electricity Distributors.*

Table 5- 6: Historical System Reliability Indicators

Reliability Indicator	Target	2015	2016	2017	2018	2019	5 Year Average
SAIDI - including loss of supply		2.31	1.68	1.51	2.35	2.43	2.06
SAIFI - including loss of supply		1.70	1.41	1.69	1.98	1.83	1.72
SAIDI - excluding loss of supply		2.05	1.52	1.37	1.98	2.03	1.79
SAIFI - excluding loss of supply		1.42	1.38	1.55	1.65	1.63	1.52
SAIDI - excluding loss of supply & major events	2.58	2.05	1.52	1.37	1.98	2.03	1.79
SAIFI - excluding loss of supply & major events	1.30	1.42	1.38	1.55	1.65	1.63	1.52

As can be seen from the table above, NPEI has not reported any Major Event outages during the 2015 – 2019 historical years.

Section 2.1.4.2 of the RRR defines a Major Event as follows:

"'Major Event' is defined as an event that is beyond the control of the distributor and is:
a) unforeseeable;
b) unpredictable;
c) unpreventable; or
d) unavoidable.

Such events disrupt normal business operations and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, they take significantly longer than usual to repair, and they affect a substantial number of customers."

During recent years, NPEI has typically experienced 1 or 2 weather-related events each year, which have had a significant impact on reliability. Here, NPEI has defined significant to mean impacting 10% of customers (i.e. approximately 5,600 customers), or resulting in an equivalent number of customer hours of interruption (i.e. approximately 5,600 customer hours).

In NPEI's view, these typical weather-related events do not meet the definition of a Major Event, since they do not *"occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system".* However, NPEI tracks these events internally, and typically includes them in NPEI's Management Discussion and Analysis for the annual *Scorecard of Electricity Distributors.*

During the past 5 historical years, NPEI has identified 7 such weather-related events which have either impacted 10% of customers or caused an equivalent number of customer hours of interruption.

Table 5- 7: Significant Weather-Related Events

Date	Description	# of Customer Interuptions	# of Customer Hour Interruptions	Average # of Customers	Contribution to Annual SAIDI	Contribution to Annual SAIFI
March 2-3, 2015	Freezing Rain	3,987	9,842	53,002	0.19	0.08
June 20, 2016	Lightning	5,415	9,416	53,671	0.18	0.10
March 8, 2017	Wind Storm	8,255	7,426	55,013	0.13	0.15
April 4, 2018	Wind Storm	11,052	11,769	55,811	0.21	0.20
May 4, 2018	Wind Storm	9,767	11,733	55,811	0.21	0.18
Feb 24-25, 2019	Wind Storm	10,454	4,108	56,025	0.07	0.19
Dec 1-2, 2019	Freezing Rain	12,885	33,199	56,025	0.59	0.23

Table 5.8 below shows NPEI's System Reliability Indicators, restated to exclude the impact of the 7 weather-related events identified in Table 5-7 above.

Table 5- 8: Historical System Reliability Indicators (Excluding Significant Weather Related Events)

SQI (Excluding Significant Weather-Related Events)	2015	2016	2017	2018	2019
SAIDI - excluding loss of supply & significant weather events	1.86	1.34	1.23	1.56	1.36
SAIFI - excluding loss of supply & significant weather events	1.34	1.28	1.40	1.28	1.21

The data included in the tables above is presented in the charts below.

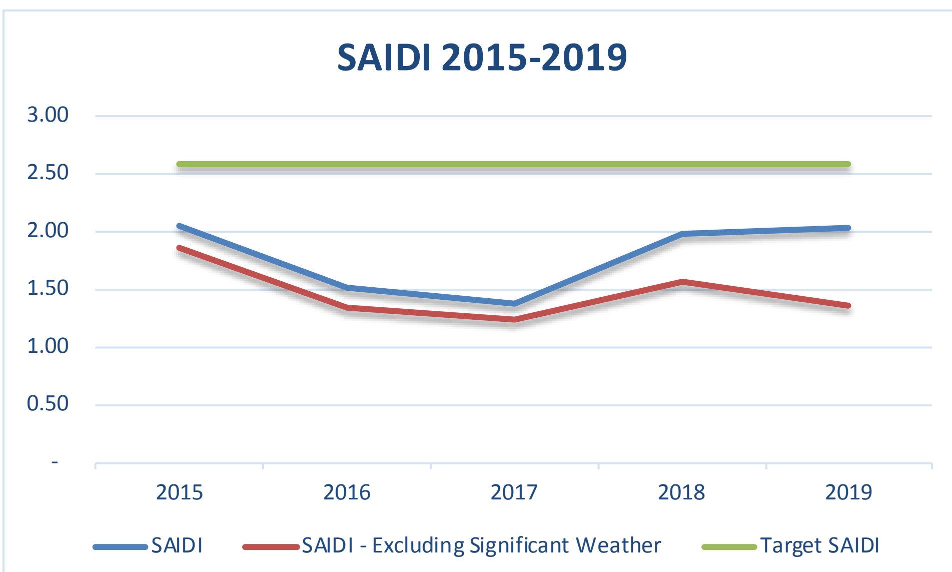


Figure 5- 14: Historical SAIDI from 2015 to 2019 (Including Significant Weather Events)

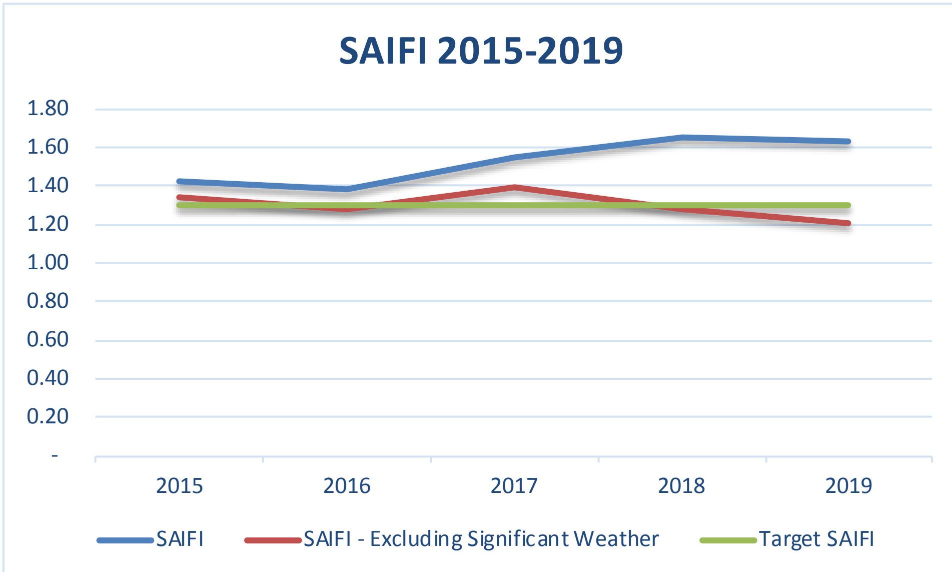


Figure 5- 15: Historical SAIFI from 2015 to 2019 (Including Significant Weather Events)

The charts above indicate that both SAIDI and SAIFI have been trending relatively consistently over the historical period.

Outages by Cause Code

The following sections and figures provide the breakdown of historical outages for years 2015-2019 regarding the number of outages, number of customers interrupted, and number of customer hours experienced by the outages. Tracking outage performance by cause code provides valuable information on specific outage causes that need to be addressed to improve negative trending. As with the reliability indices, the five-year historical performance range is used as a target and results outside this range indicate positive or negative trending.

Outages Experienced

Table 5-9 presents the count of outages broken down by cause code. The number of outages is an indication of outage frequency and impact customers differently based on customer class. For example, residential customers may tolerate a larger number of outages with shorter duration while commercial and industrial customers may prefer less outages with longer duration thereby reducing overall impact on production and business disruption. NPEI reviews outages and takes steps such as additional tree trimming, installation of animal guards and replacement of older porcelain insulators to reduce the number of outages that are controllable.

Table 5- 9: Outages by Cause Code

Cause Code	2015	2016	2017	2018	2019	Total Outages	%
0 - Unknown/Other	30	33	20	9	8	100	2.04%
1 - Scheduled Outage	497	492	361	271	318	1,939	39.48%
2 - Loss of Supply	19	10	31	39	51	150	3.05%
3 - Tree Contacts	34	33	65	60	86	278	5.66%
4 - Lightning	25	17	29	5	29	105	2.14%
5 - Defective Equipment	342	280	254	330	323	1,529	31.13%
6 - Adverse Weather	18	20	82	68	126	314	6.39%
7 - Adverse Environment	3	4	0	4	3	14	0.29%
8 - Human Element	5	4	5	8	8	30	0.61%
9 - Foreign Interference	80	88	109	86	89	452	9.20%
Total	**1,053**	**981**	**956**	**880**	**1,041**	**4,911**	**100%**

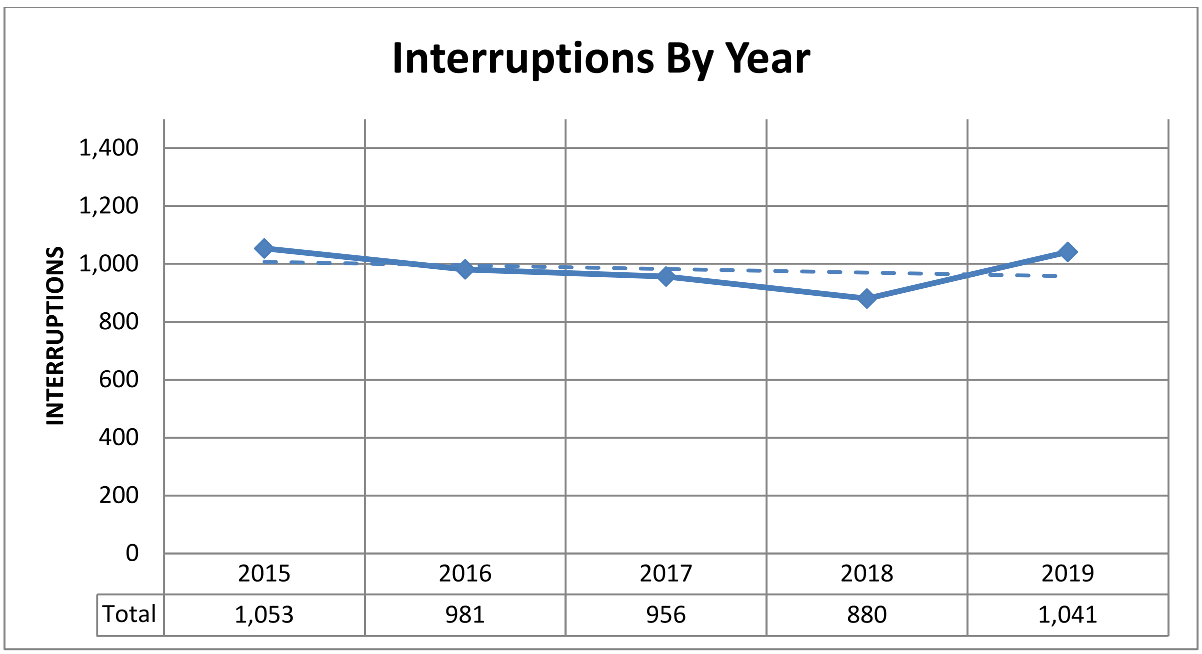


Figure 5- 16 – *Interruptions by Year (All Cause Codes)*

The total number of interruptions over the historical period varies from a low of 880 to a high of 1053 and shows a relatively stable trend within the period. This represents an average of 2.41 to 2.88 interruptions per day. The number of outages by itself does not tell the full story on reliability and should be accompanied by other metrics such as number of customers impacted and the outage duration.

Scheduled outages show a relatively stable, to decreasing trend. This category consistently accounts for the largest number of interruptions (39.48%). However, as shown in Table 5-10, *Scheduled Outages* is not the largest contributor to number of customers interrupted. This is primarily a result of being able to pre-plan outages so that the number of customers impacted is minimal. That is, lines and equipment are taken out of service in a controlled manner and switching is performed whenever possible to supply customers from alternate sources of supply. Schedule outages are also necessary to reduce safety hazards associated with working around energized circuits.

The number of outages associated with *Loss of Suppl*y is extremely small due to the redundancy built into the transmission supply system and the NPEI-owned transformer station. Most interruptions occur on the downstream 27.6kV, 13.8kV, 8.3kV and 4.16kV feeder systems. The number of customers impacted by a Loss of Supply outage has the potential to be significant because of the customer count associated with a transformer station versus a feeder or distribution equipment. These outages are mitigated through transformer stations redundant design and coordination with HONI to reduce the occurrences of operating transformer stations in a non-redundant mode.

The number of outages caused by *Tree Contacts* show an overall increasing trend over the historical period. There is also a corresponding increase in the number of customer interruptions and , the customer hours interrupted as shown in Table 5-11. This aligns with the increase in adverse weather, namely wind and ice storms. Tree contact outages are mitigated through effective tree trimming programs to maintain line clearance standards. NPEI operates a five-year tree trimming cycle to clear trees in all geographical zones in its service territory. While tree trimming programs help to mitigate outages caused by tree contacts, there are events beyond NPEI's control that normally occur, such as high winds and freezing rain that can result in trees falling and coming in contact with power lines despite being trimmed to acceptable standards.

The number of outages caused by *Defective Equipment* shows an overall stable trend over the historical period. These outages are mitigated through effective maintenance programs and renewal programs for end-of-life assets.

The number of outages caused by Adverse Weather shows an increasing trend starting in 2017. While NPEI does not report any Major Events during the historical period, we do note that there were five significant weather events over the years 2017 through 2019. These outages are mitigated through efforts to harden the distribution system against adverse weather.

The number of outages caused by *Adverse Environment* are consistently small (less than 5) and do not significantly impact NPEI's reliability performance.

Human Element outages are consistently small (less than 8) and do not significantly impact NPEI's reliability performance.

Foreign Interference outages show a relatively stable trend over the historic period. These events are primarily due to motor vehicle accidents and animal contacts. Some of these outages (such as animal contact) are mitigated through increased use of barriers and environmental design considerations. Other foreign interference outages (e.g. vehicle impacts) are more difficult to mitigate.

Customers Interrupted (CI) and Customers Hours Interrupted (CHI)

The number of customers interrupted is a measure of the extent of outages. Customer Hours Interrupted is a measure of outage duration and the number of customers impacted. The tables and figures below provide the historical values and trends for both CI and CHI.

Table 5- 10: Customer Interruptions by Cause Code

Cause Code	2015	2016	2017	2018	2019	Total Customer Interruption	%
0 - Unknown/Other	6,060	6,724	14,808	7,148	2,397	37,137	7.87%
1 - Scheduled Outage	7,164	7,855	4,792	4,387	5,293	29,491	6.25%
2 - Loss of Supply	15,138	1,923	7,866	18,202	11,432	54,561	11.57%
3 - Tree Contacts	4,618	10,278	11,563	9,498	19,180	55,137	11.69%
4 - Lightning	828	7,220	1,086	1,493	6,652	17,279	3.66%
5 - Defective Equipment	37,265	27,623	16,595	35,899	24,493	141,875	30.08%
6 - Adverse Weather	4,941	3,931	9,591	19,522	31,493	69,478	14.73%
7 - Adverse Environment	35	2,616		429	7	3,087	0.65%
8 - Human Element	2,752	962	419	263	48	4,444	0.94%
9 - Foreign Interference	11,104	6,799	26,146	13,548	1,548	59,145	12.54%
Total	**89,905**	**75,931**	**92,866**	**110,389**	**102,543**	**471,634**	**100%**

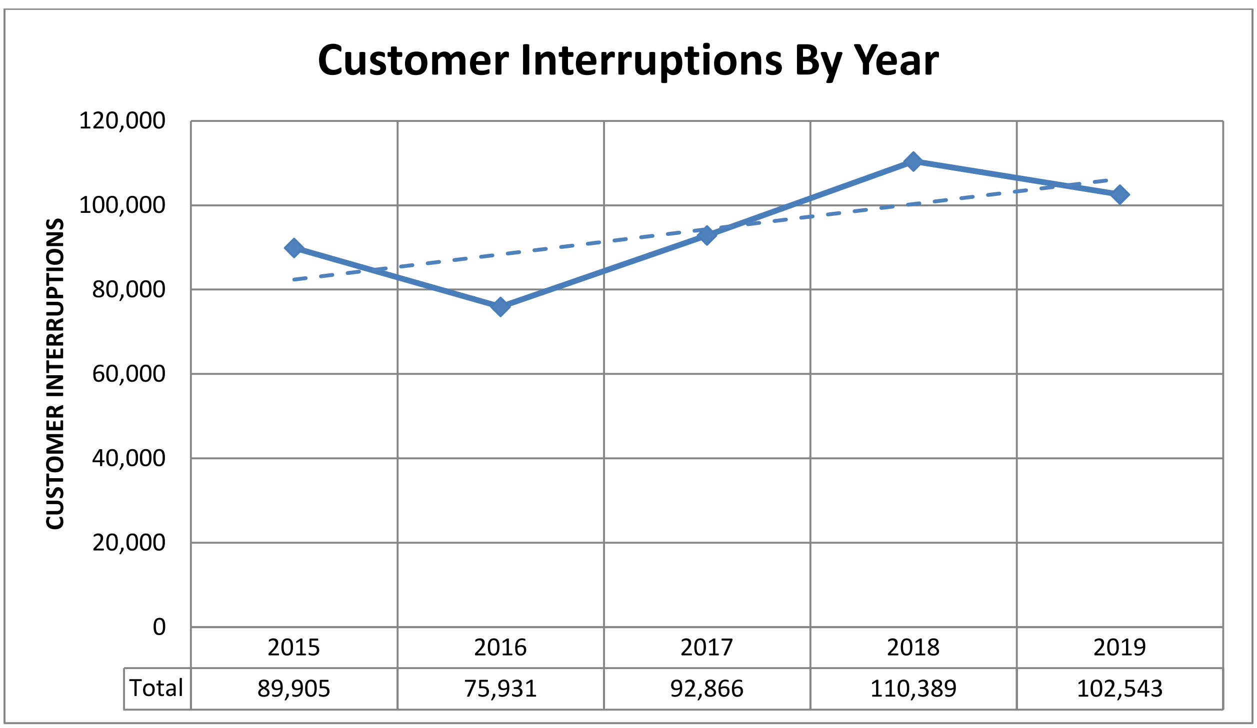


Figure 5- 17: Customer Interruptions by Year

Table 5- 11: Customer Hours of Interruptions by Cause Code

Cause Code	2015	2016	2017	2018	2019	Total Customer Hour Interruption	%
0 - Unknown/Other	1,514	3,095	6,955	753	1,651	13,969	2.62%
1 - Scheduled Outage	11,549	14,003	5,459	7,653	8,961	47,624	8.94%
2 - Loss of Supply	13,688	8,886	7,629	20,672	22,409	73,283	13.76%
3 - Tree Contacts	4,225	8,916	16,576	12,754	22,923	65,394	12.28%
4 - Lightning	1,116	11,194	1,493	666	4,890	19,358	3.64%
5 - Defective Equipment	41,414	26,626	20,619	53,829	27,743	170,232	31.97%
6 - Adverse Weather	14,197	2,298	8,976	17,341	42,969	85,781	16.11%
7 - Adverse Environment	29	1,869		498	21	2,417	0.45%
8 - Human Element	237	486	94	373	86	1,275	0.24%
9 - Foreign Interference	10,573	8,549	15,160	16,732	2,193	53,207	9.99%
Total	**98,542**	**85,922**	**82,960**	**131,271**	**133,844**	**532,540**	**100%**

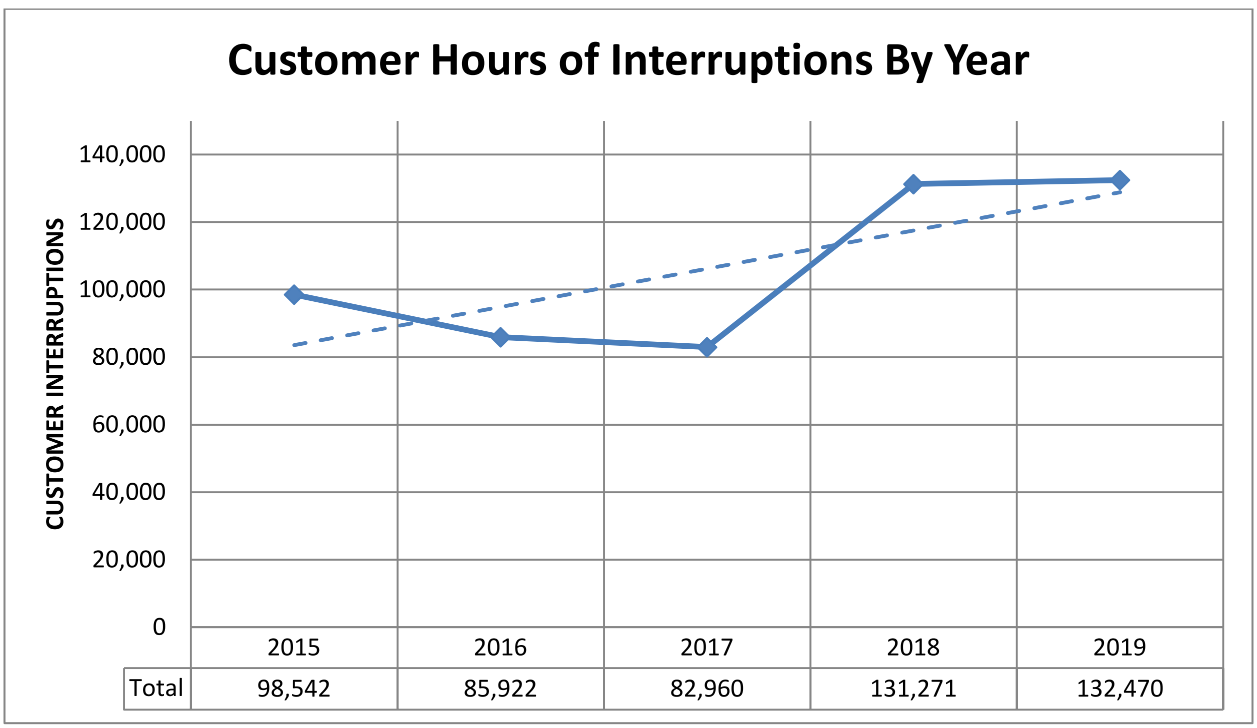


Figure 5- 18: Customer Hours of Interruptions by Year

The largest contributors to the duration and the number of customer interruptions in the historical period are *Defective Equipment, Foreign Interference and Adverse Weather*.

Defective Equipment is the largest contributor to customers interrupted (CI) and as observed in the tables above, it is also the largest contributor to customer hours interrupted (CHI). The customer hours interrupted (CHI) due to defective equipment shows a significant amount of variation over the historical period with CHI of 41k to 53k in years 2015 and 2018 and in the low to mid 20k range for years 2016, 2017 and 2019. The increase in CHI for 2015 was attributed to an increase in the number of arrester failures and the increase in CHI in 2018 was primarily due to a premature failure of the power transformer at NPEI's Campden DS.

NPEI replaces defective equipment in the system to ensure a continued reliable supply of electricity to its customers. NPEI's maintenance and inspection program has been an effective means of replacing infrastructure at end of life. NPEI intends to continue to diligently maintain, inspect and service its equipment so that useful life is maximized without compromising the customer's reliability of service.

Foreign Interference is the second largest contributor to CI over the historical period. Interruptions due to foreign interference such as animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects, are typically beyond the control of NPEI. NPEI has implemented programs such as animal guards to reduce the incidents of animal contacts and actively encourages customers, contractors and residents to participate in its "Call before you Dig" program to identify underground plant.

Adverse Weather is the second largest contributor to CHI over the historical period. The number of outages caused by Adverse Weather shows an increasing trend starting in 2017. While NPEI does not report any Major Events during the historical period, we do note that there were five significant weather events over the years 2017 through 2019. These outages are mitigated through efforts to harden the distribution system against adverse weather through our overhead rebuild programs as well as ensuring that we maintain our tree trimming cycle.

Performance Trends into the DSP

NPEI uses the CAIDI, SAIDI and SAIFI reliability indexes to gauge the system reliability performance and maintain a tight control over capital and maintenance spending. NPEI will also use the feeder performance indices to provide more targeted mitigation measures. Looking forward, DSP investment priorities are expected to result in outcomes that maintain existing reliability performance. Historical reliability performance of NPEI's system provides insight as to how the system is performing. NPEI's intention is to continuously improve the reliability of the system with incremental investments such as installing electronic reclosers connected to the SCADA system for remote monitoring and control, targeted system rebuilds and continued preventive maintenance programs. Furthermore, NPEI will be able to specifically target feeders that are contributing the most in terms of total CHI and CI. The expectation is that NPEI would improve the overall reliability performance by analyzing the key drivers of system performance and working to eliminate the largest contributors to interruptions. Additionally, tracking system performance by major cause codes aides NPEI in identifying the required investments needed to be prioritized. For example, tree or animal contact related outages might indicate that NPEI needs to review its' tree trimming program or look to target specific areas for additional wildlife protections. Additional analysis would further confirm the appropriate approach.

Additionally, NPEI has implemented several programs to reduce the number of outages that are controllable. These programs include:

- Planned renewal of end-of-life assets such as poles, transformers and cables;
- Proactive vegetation management;
- Inspection of plant to identify potential problems; and
- Inspection and testing of poles

5.2.3.2 Cost Efficiency and Performance

5.2.3.2.1 Cost Control

5.2.3.2.1.1 Methods and Measurements

The OEB has ranked all Ontario LDCs in one of five efficiency groups (1 – 5) with Group 1 being deemed the most efficient and Group 5 being deemed the least efficient.

Cost Metrics

Managing costs is a responsibility taken seriously at NPEI. The levels of spending are measured and prudently controlled so that customer rates are minimally affected. Total cost per customer is calculated as the sum of NPEI's capital and operating costs divided by the total number of customers served:

$$Total\ Cost\ per\ Customer = \frac{\sum Capital\ \&\ O\&M\ costs}{Number\ of\ Customers\ served}$$

NPEI as well collects the trend data on total cost per kilometre of line and total cost per MW. The total cost is calculated as the sum of NPEI's capital and operating costs divided by the total kilometres of line in service at NPEI or by the peak MW for each measure respectively:

$$Total\ Cost\ per\ Kilometer\ of\ Line = \frac{\sum Capital\ \&\ O\&M\ costs}{Kilometers\ of\ Line}$$

$$Total\ Cost\ per\ MW = \frac{\sum Capital\ \&\ O\&M\ costs}{Peak\ MW}$$

Additionally, NPEI tracks the additional metrics introduced in OEB's Chapter 5 update; the O&M Cost per customer and O&M Cost per kilometre of line. The metrics are calculated with the total O&M costs divided by the respective number for each metric, defined as follows:

$$O\&M\ per\ Customer = \frac{\sum\ O\&M\ costs}{Number\ of\ Customers\ served}$$

$$O\&M\ Cost\ per\ Kilometer\ of\ Line = \frac{\sum O\&M\ costs}{Kilometers\ of\ Line}$$

In compliance with the Filing Requirements, NPEI attaches the OEB Appendix 5-A as part of this filing found in Appendix J which identifies the total CAPEX cost metrics.

5.2.3.2.1.2 Historical Performance

Efficiency Assessment

NPEI is currently ranked in Group 3 with respect to Efficiency Assessment (stretch factor = 0.3%). Group 3 is defined as having actual costs within 0% to 10% of predicted costs. NPEI's goal is to continue remaining in this efficiency cohort. Going forward, NPEI intends to continue implementing productivity and efficiency improvements to help offset some costs while maintaining the reliability and quality of its distribution system.

Cost Metrics (Per OEB Benchmarking)

As can be seen in the figures below, NPEI's capital cost metrics have been generally consistent (averaging 3%) over the historical period. Furthermore, the total cost per peak kW fluctuates from year to year but shows a generally consistent trend. The variation would be attributable to the varying weather as well as customers being more aware and efficient with power usage combined with the variation in capital expenditures. NPEI's operation and maintenance (O&M) cost metrics have experienced a minor increase over the historical period, however, the increases seen are consistent with annual inflation and system growth. This trend is expected to continue over the forecast years, as additional assets being installed require incremental O&M spending.

As part of customer engagement, NPEI considers the projects that would have a minimal cost impact on customers while also returning a benefit with respect to the quality of the service. These trade-offs are considered and communicated with customers to understand their preference. The projects and programs considered within this DSP period take a proactive approach so that NPEI would be able to maintain its distribution system while minimizing the cost per customer as much as possible.

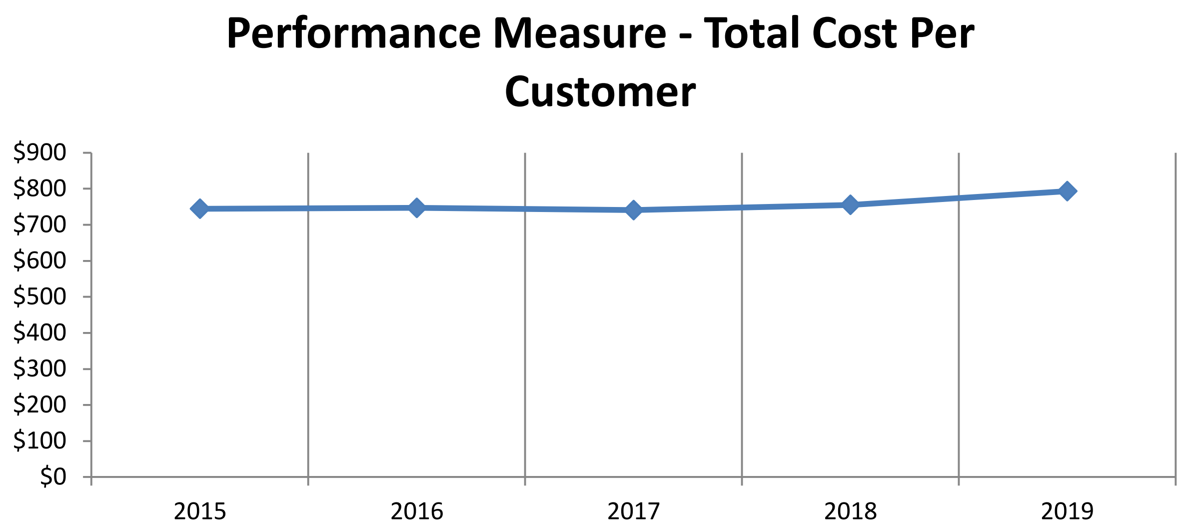


Figure 5- 19: Total Cost per Customer

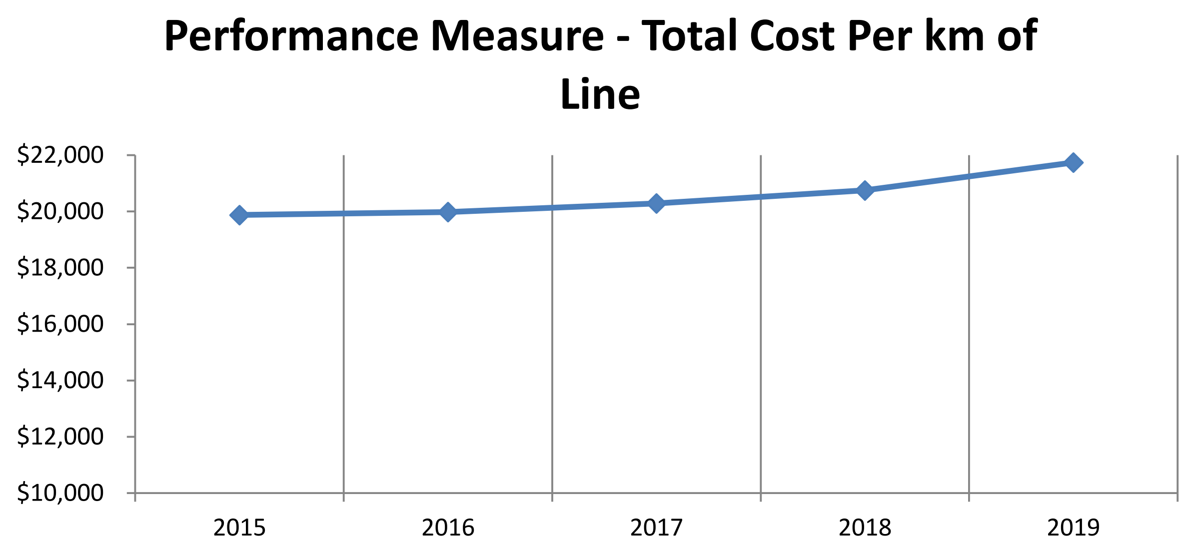


Figure 5- 20: Total Cost per km of Line

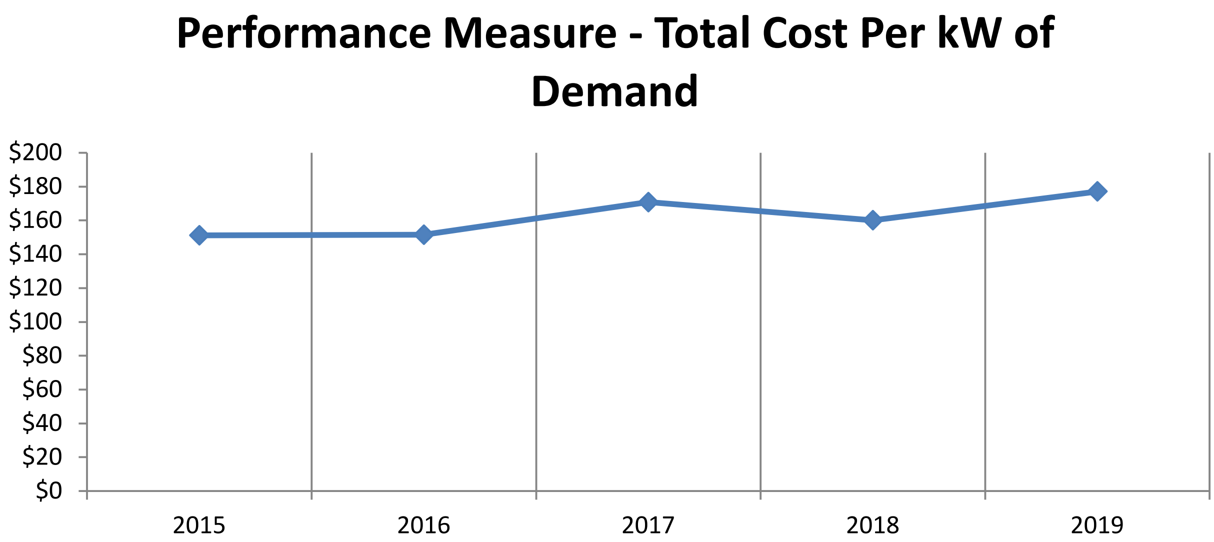


Figure 5- 21: Total Cost per kW of Demand

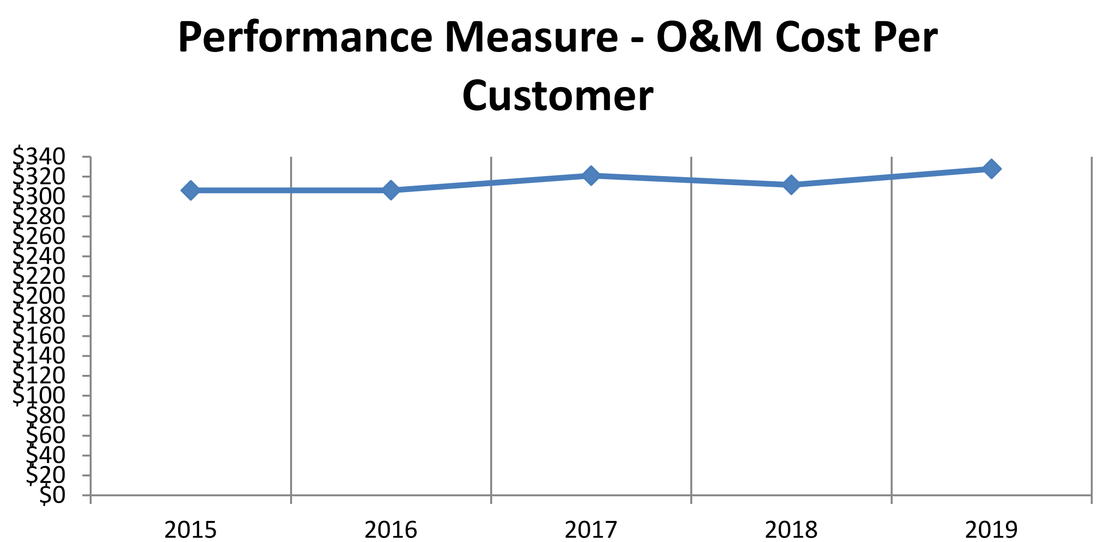


Figure 5- 22: O&M Cost per Customer

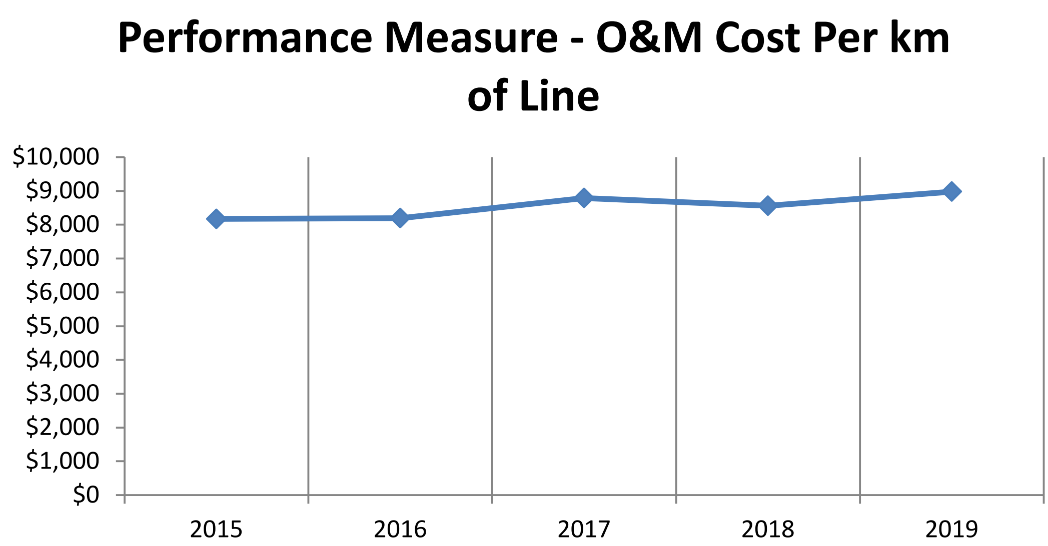


Figure 5- 23: O&M Cost per km of Line

5.2.3.2.2 Distribution System Plan Implementation Progress

5.2.3.2.2.1 Methods and Measures

Project/program variance analysis

NPEI monitors capital projects and maintenance program spending. Going forward, for material capital projects, actual costs are to be compared to estimates and variances exceeding designated thresholds will be reviewed by operations and engineering staff to determine the cause of the variation. Lessons learned will be incorporated into future estimates and project management. The performance measure is that these projects and programs are completed within +/-20% of budget and are executed within the budget year unless carryover spending has been specifically identified.

For all customer demand (billable) work (Offers to Connect), NPEI conducts a variance analysis. If the actual cost is greater than 10% of the estimated cost an explanation is sought from the operations and engineering staff responsible for the job.

Planned maintenance programs are expected to be completed within the budget and calendar year. NPEI's target for this measure is that actual variances are within 10% of estimate.

DSP Spending Progress Report

NPEI monitors execution of projects and programs included in the DSP. On a monthly basis, NPEI reviews project progress to date. Where forecast to year end is materially greater than the budget, NPEI will review projects and determine if they can be deferred to a later date or reduce their scope. Mandatory projects for a given year are typically not subjected to deferral.

On an annual basis, NPEI will calculate its actual capital spending compared to the approved capital budget. NPEI's target for this measure is that DSP actual spending to be within 10% of approved DSP capital budget.

5.2.3.2.2.2 Historical Performance

Project/program variance analysis

NPEI budget to actual spending has been impacted by significant amounts of mandatory work during the historical period. NPEI has limited ability to affect mandatory work schedules as these are driven by new connection requirements. NPEI, has utilized historical mandatory work levels to predict the amount of expected System Access work for the forecast period. NPEI will monitor and track the project and program variances moving forward with the current DSP.

DSP Spending Progress Report

The table below provides the actual capital spending compared to the approved capital budget for each year of the Historical Period.

Table 5- 12: DSP Spending Progress - Historical

Measure	2015	2016	2017	2018	2019
DSP Spending Progress	94.55%	95.97%	100.69%	99.27%	88.79%

5.2.3.2.2.3 Performance Trends into the DSP

Project/program incorporation into the DSP

Projects and programs have been prepared in consideration that spending must be achievable with the resources that are available in a timely manner. Projects are to be completed in the year they are budgeted. In many cases, larger scope projects have been broken into multiple phases, with each phase planned to be completed within a specified year. The DSP investment planning has been set up to design, issue, and construct reasonable amounts of works that can be achieved within the forecast period. Annual DSP spending exceeding a designated threshold of +/- 10% will require a detailed variance explanation.

5.2.3.3 Asset/System Performance

NPEI collects a variety of statistics and analyzes the data to assess system performance. These are utilized as inputs to the asset management program and capital prioritization processes.

5.2.3.3.1 Safety Performance

5.2.3.3.1.1 Methods and Measures

Maintaining a high level of employee safety, health & wellness and public safety are key corporate objectives. Safety is monitored on an ongoing basis. Reports on all incidents and accidents are provided to the President & CEO and relevant Senior Executive Team members. A summary of any incidents and accidents is included in the Asset Management report that is provided to the NPEI Board of Directors.

The safety measures monitored by NPEI include:

– Public Awareness of Electrical Safety

– Compliance with Ontario Regulation 22/04

– Serious Electrical Incidents

In early 2004 changes in regulation advanced public electrical safety with the approval and introduction of Ontario Regulation 22/04 addressing Electrical Distribution Safety. Ontario Regulation 22/04 - Electrical Distribution Safety establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. The regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service by NPEI.

The Electrical Safety Authority enforces regulation for licensed distributors in Ontario. In order to ensure compliance, the Electrical Safety Authority requires licensed distributors to engage in third party audits. NPEI arranges for third party audits annually to ensure compliance with the regulation.

NPEI's target is to remain in compliance in all categories being audited.

5.2.3.3.1.2 Historical Performance

NPEI strives to maintain, public safety awareness, compliance with Ontario Regulation 22/04 and safe operation of our system. The table below highlights NPEI's historical performance for each of the three components. The two serious electrical incidents for 2019 represent voluntary reports to the ESA by NPEI of cases where there was evidence of attempted copper theft in proximity to primary distribution voltage levels. No known injuries were reported.

Table 5- 13: Safety Performance by Year

Measure	2015	2016	2017	2018	2019
Level of Public Awareness (%)	84.00	84.00	83.00	83.00	Not Available
Level of Compliance with Ont. Reg. 22/04	C	C	C	C	C
Serious Electrical Incident Index Number of General Public Incidents	0	0	0	0	2
Serious Electrical Incident Index Rate per 10, 100, 1000km of line	0	0	0	0	0.988/1000 km line

In order to ensure compliance, the Electrical Safety Authority requires licensed distributors to engage in third party audits. NPEI arranges for third party audits annually to ensure compliance with the regulation. The table below summarizes audit findings for the period 2014 to 2019:

Table 5- 14: ESA Audit Findings Summary 2014-2019

Annual Compliance Audit Findings	2015	2016	2017	2018	2019
Non Compliant	0.00	0.00	0.00	0.00	Not Available
Needs Improvement	1.00	1.00	0.00	0.00	Not Available
Total Findings	1.00	1.00	0.00	0.00	Not Available

NPEI reviews and responds to the Electrical Safety Authority regarding findings of non compliance or opportunity for improvement. NPEI implements action plans in order to remedy findings of non-compliance.

5.2.3.3.1.3 Performance Trends into the DSP

Public Awareness

NPEI continues to promote continued education, awareness and application of safe work practices and as such safety continues to play a key role in project prioritization. Ensuring a safe environment for workers and the public has been taken into consideration in the development of the DSP and NPEI's asset management and capital expenditure planning process.

Reg. 22/04

NPEI continues to demonstrate prudent compliance with O. Reg. 22/04 and as such ESA compliance continues to play a key role in project prioritization. Ensuring Reg. 22/04 compliance is maintained has been taken into consideration in the development of the DSP and NPEI's asset management and capital expenditure planning process.

Serious Electrical Incidents

NPEI continues to put measures in place to prevent SEI that are within its control and has identified a number of pole line rebuild projects that will eliminate some of the hazards such as small conductors or poles that are at end of life. The two serious electrical incidents for 2019 represent voluntary reports to the ESA by NPEI of cases where there was evidence of attempted copper theft in proximity to primary distribution voltage levels. No known injuries were reported.

5.2.3.4 System Losses

5.2.3.4.1 Methods and Measures

NPEI system losses are monitored annually. System design and operation is managed such that system losses are maintained within OEB thresholds, as defined in the OEB Practices Relating to Management of System Losses. Losses are monitored to ensure that the OEB 5% threshold is not exceeded.

5.2.3.4.2 Historical Performance

NPEI system losses over the historical period are shown below.

Table 5- 15: System Losses Summary 2014-2019

Metric	2015	2016	2017	2018	2019
System Losses (%)	4.00	3.72	3.78	3.78	3.74

Losses are trending in the 3.7 – 4.0% range over the historical DSP period and within the OEB 5% threshold.

5.2.3.4.3 Performance Trends into the DSP

Existing performance is within performance targets and as such there is no specific impact on the DSP. For the period of the DSP, NPEI has adopted a performance target of maximum 5% system loss.

5.2.4 Realized Efficiencies due to Smart Meters

NPEI has capitalized on the installation of smart meters and Advanced Metering Infrastructure (AMI) communications networks by adapting our process and use of technology to maximize operational efficiencies in the following ways:

- NPEI has integrated its advanced meter infrastructure (AMI) to the InService Outage Management System (OMS). Real time reporting of 'last gasp' notifications from meters to the OMS provide instantaneous prediction of failed devices on the distribution system resulting in improved response and restoration times.
- NPEI has integrated the AMI data into the NorthStar CIS (Customer information System). This data is utilized for customer billing purposes, however, it is also utilized for importing aggregated transformer load information into our GIS (Geographical Information System) and DESS system analytical model for performing load flow and system planning studies. Having more accurate and timely loading data allows NPEI to more accurately plan for system expansions and modifications needed to accommodate load growth and prevent overloading of equipment.
- NPEI utilizes the remote examination feature (pinging) of smart meters to assist in diagnosing power related issues without deploying a crew.
- NPEI utilizes the power quality alarming feature of smart meters to automatically alert engineers and metering staff of voltage sags/swells or reverse power issues, allowing them to be responded to in a timely manner.

5.3 ASSET MANAGEMENT PROCESS

This section provides an overview of NPEI's asset management process and the direct links between this process and the expenditure decisions that comprise the capital investment plan which forms a part of this DSP.

5.3.1 Asset Management Process Overview

5.3.1.1 Asset Management Objectives

NPEI's asset management objectives align with NPEI's core business values.

Vision Statement: "To be recognized as exceptional in delivering services and value, to our customers and communities"

Mission Statement: "To deliver safe, efficient and reliable electricity with excellent customer service and community value, provided by engaged employees".

NPEI strives to achieve its mission through key corporate business values. NPEI and its staff will maintain conduct with commitment to the values of:

- Responsibility- we provide services with safety first for our customers and employees
- Integrity- we are ethical and our actions are truthful and trustworthy
- Fairness- we treat everyone equally and free of bias
- Respect- we listen to each other and see value that each member of the team brings and respect the needs of our stakeholders
- Transparency- we are open and accountable for our actions and decisions

The key outcome is maintaining the desired level of customer service at the best appropriate cost accepted by NPEI's customers.

NPEI's core business values form the foundation for NPEI's asset management objectives which are:

- Construct, maintain and operate all assets in a safe manner;
- Monitor and address asset condition issues in a timely manner to ensure the continued reliable supply of electricity delivery;
- Ensure asset management plans align with customer expectations;
- Manage investment planning to mitigate rate impacts while maintaining corporate financial stability and long-term sustainable performance; and
- Ensure that environmental considerations are considered in the design and management of the distribution system.

An integral part of achieving the asset management objectives are inspection, maintenance and replacement programs, to ensure system performance is sustained during the entire asset service life. NPEI has inspection, maintenance and replacement programs in place to achieve this.

To provide consistency with its Strategic Goals, NPEI has adopted an asset management strategy that provides direction for the management of assets while recognizing realistic service and performance goals. The asset management strategy ensures a continual and consistent focus on delivering services in a way that balances risk and long-term costs.

NPEI uses 5 key strategic objectives as the basis for business planning:

- CUSTOMER SATISFACTION
    - Enhance customer satisfaction through high quality service.
    - Promote the efficient use of electricity through education, and delivery of conservation initiatives.
    - Continue to deliver reliable electricity at reasonable rates.
    - Minimize system outages.

- FACILITIES OPTIMIZATION
    - Plan expansion of the transformation and distribution systems to meet the electrical needs of current and future customers.
    - Refurbish aging plant facilities and equipment in a cost effective manner.
    - Enhance system performance and reliability

- PUBLIC POLICY
    - Participate on industry advisory panels and incorporate any new legislated initiatives into the system.
    - Implement Smart Grid initiatives to improve reliability and accommodate Distributed Energy Resources (DERs).
    - Support environmental programs (Reduce, Reuse, and Recycle).

- SAFETY AND WELLNESS
    - Promote safety awareness for our associates and the community.
    - Strengthen NPEI's "Safety Culture"
    - Promote wellness initiatives with NPEI associates.

- CORPORATE LEADERSHIP
    - Provide our associates with the necessary skills to meet customer needs and expectations.
    - Maintain long-term financial viability.
    - Develop resources to promote the sustainability of our operations.
    - Maintain regulatory compliance.
    - Continue to build value for our Shareholders.

These strategic goals align themselves with 4 key criteria used in the prioritization of planned capital expenditures:

- Reliability / Performance
- Efficiency
- Safety
- Community Relations / Regulatory

This Distribution System Plan builds upon the Distribution System Plan (DSP) developed as part of the 2014 Distribution Rate Application. In particular, the 2014 Asset Condition Assessment (ACA) previously used to support NPEI's asset management strategies has been updated in 2019 by Kinectrics Inc. ("Kinectrics"). The ACA report provided by Kinectrics is entitled: "Distribution Asset Condition Report - 2018" and is included in Appendix of this document. The asset condition data used to support the Asset Condition Assessment were provided to Kinectrics for the following major asset categories:

- Power Transformers
- Large Pad-mounted Transformers
- Small Pad-Mounted Transformers
- Pole Top Transformers
- Poles
- Pad-Mounted Switchgear
- Underground Primary Cables
- Overhead Primary Conductor

NPEI monitors feeder performance through data collected by its Outage Management System. Feeder performance values are used in conjunction with asset health indices as key drivers for capital expenditure planning to identify feeders that require urgent attention.

The DSP also considers historical capital expenditure and potential external drivers which impact the mix and scope of capital investments. Capital investments for the period covered by this DSP are mapped according to the following project categories:

System Access: These are investments to support municipal development, regional development, and demand for new/upgraded connections. These include road relocation projects in partnership with land use authorities and expansions for customer connections or property development. One key driver that has been considered in this plan is the proposed development of the new South Niagara Hospital which is currently planned for construction during the forecast period of this DSP.

System Renewal: Investments categorized as system renewal are required to sustain existing operations maintaining an acceptable level of asset performance. System Renewal expenditures are based on the results of the 2019 Asset Condition Assessment report. The ACA report provides health indices for major asset categories which NPEI uses to prioritize asset replacements. In addition to the ACA, NPEI categorizes some of its programs as System Renewal based on identification of assets at end of life. An example of this is the kiosk replacement program where the holistic population of the asset base is at end of life.

System Service: These investments include upgrades and modifications to NPEI's distribution system to meet reliability expectations and provide future capacity. While these investments enhance NPEI's operational capabilities, they also typically result in distribution system loss reduction. The investments include deployment of new technologies to improve operational effectiveness.

General Plant: Investments in general plant support NPEI's capital expenditure plan. These investments are driven from the attached 2019 Fleet Assessment and 2019 IT Assessment.

A description of projects and programs associated with these categories is provided in greater detail in this document.

5.3.1.2 Asset Management Process Detail

The Asset Management Process is the foundation for development of NPEI's business plan.

depicts the high level process followed by NPEI with a description of the process as follows:

Needs Identification

There are 3 high level categories of inputs to the Needs Identification process: External Drivers, Internal Drivers, and Strategic Investments. Each of these are described below:

External Drivers

The introduction of external drivers to the process is dynamic and can trigger modification to the project prioritization and spending as contained in this DSP. There are several factors that can play a role in the success of the work execution plan. Some of these are expanded on below. Other factors such as resource availability, economic conditions, and regulatory changes such as accommodating DER’s, can determine the success of plan execution. Such influences may not only lead to changing prioritization of investments but may also lead to redefinition of corporate business values and strategic objectives.

Customer (Demand) Connections

Customer connection forecasts are based on timing information received from Municipal Planning staff, planning reports (provincial, regional, municipal), developer submissions and inquiries, and historical connection rates. Variances in connection timing/quantity over the period of the DSP will impact on actual connections and related System Access expenses.

Customer Preferences

The preliminary capital plan is included in our Customer Engagement workbook where we detailed the potential impact on customer bills for each of the major project areas. The feedback from this customer engagement process is utilized to make adjustments reflective of customer preferences.

Municipal / Region / MTO Road Projects

The Region, Municipalities and MTO carry out road resurfacing and other types of roadway improvements on an annual basis. Timing and location for these works are subject to short-term planning considerations, and as such, are frequently rescheduled. NPEI will be required to accommodate and react to these road projects as they occur during the period of the DSP.

Meter Re-verification – Meter Obsolescence

NPEI is required to have its residential revenue meters tested on a periodic basis, to ensure

compliance with Measurement Canada standards. In 2019 18,095 of NPEI's electronic residential meters were tested by Measurement Canada compliance sampling methods. The units passed the sample testing and their seal periods were extended for 8 years as determined by the statistical sampling process. In 2020 NPEI will be sample testing a further 25,805 units. If the units fail sample testing, they would have to be removed from service and replaced by the end of the year they are sampled in. NPEI's planning assumption is that the meters should pass compliance sampling. However, failure to pass the tests would result in an unbudgeted capital expenditure in the order of $5,493,110. This accounts for only 25,805 meters that would need to be addressed in 2020. The total unbudgeted capital expenditure for the full forecast period would be in the order of $4,402,757. There will be smaller volumes of meters requiring testing and re-verification in the 2021 – 2025 timeframe of the DSP. Meter year of testing, quantity and potential replacement costs are shown in the table below:

Table 5- 16: 2021 - 2025 Meter re-verification program

Test Year	Quantity of Meters	Cost per unit	Approx. Cost to replace
2021 Residential	2637	$212.87	$561,338.19
2021 Commercial	1178	$1,102.81	$1,299,110.18
2022 Residential	631	$212.87	$134,320.97
2022 Commercial	1430	$1,102.81	$1,577,018.30
2023 Residential	1635	$212.87	$348,042.45
2023 Commercial	0	$1,102.81	$0.00
2024 Residential	925	$212.87	$196,904.75
2024 Commercial	70	$1,102.81	$77,196.70
2025 Residential	981	$212.87	$208,825.47
2025 Commercial	0	$1,102.81	$0.00
Total	**9487**		**$4,402,757.01**

The DSP assumes that the meters will successfully pass re-verification testing.

Another potential external driver is the obsolescence of the 3G cellular network. Some news reports indicate that cellular providers may begin to phase out the 3G cellular network. NPEI currently has 1,251 meters that utilize 3G SIM cards for communications. If the 3G network is shutdown prior to the end of life of these meters, the unbudgeted replacement cost for these meters is estimated at $1,379,615, not including the capital write-off of the obsolete meters.

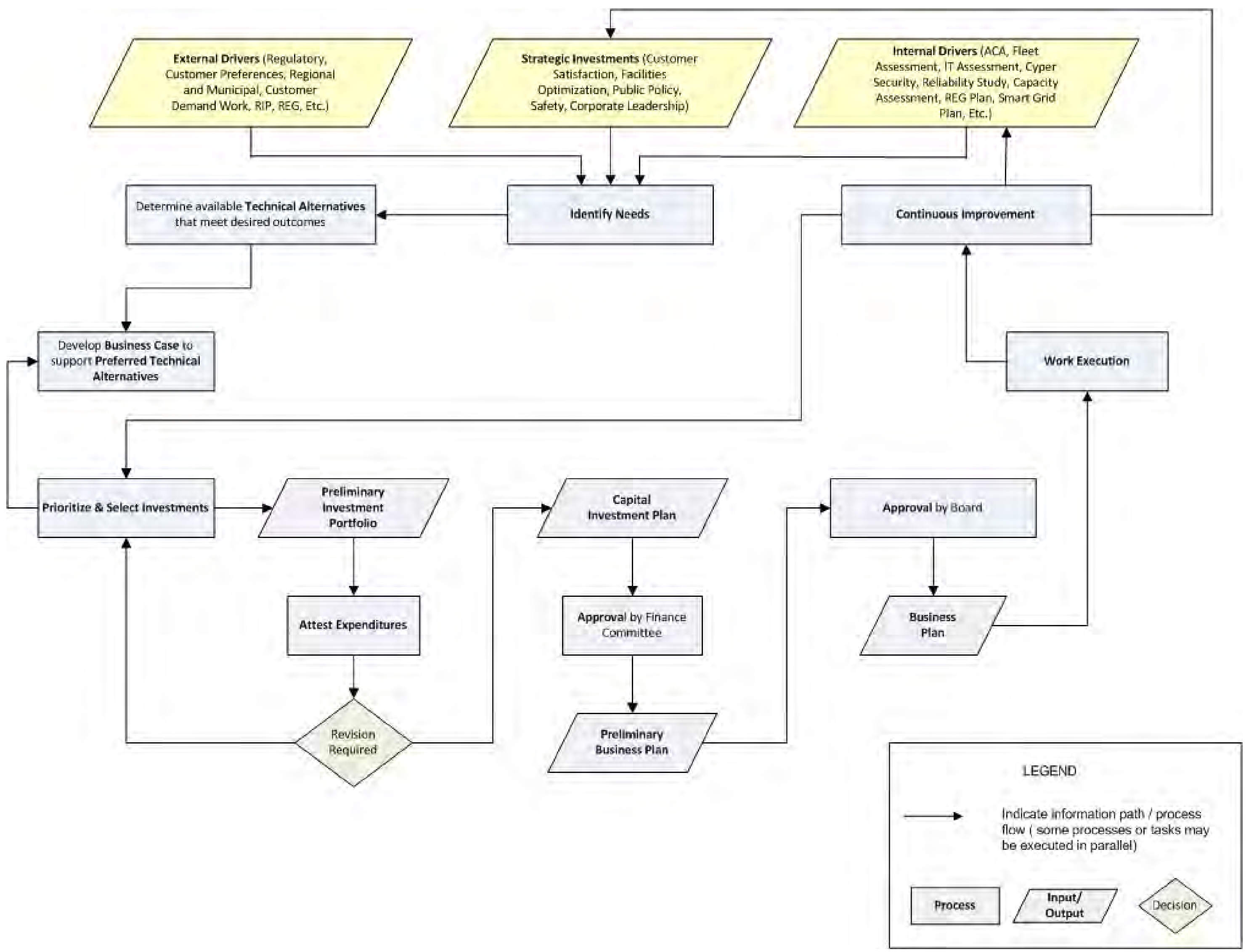


Figure 5- 24: NPEI's Asset Management Process

Internal Drivers

Internal Drivers are typically the result of studies and inspection programs aimed at maintaining asset performance levels to applicable standards. The studies and inspection programs that result in internal drivers include:

- Asset Condition Assessment
- Pole Inspection Program
- Underground Equipment Inspection Program
- Manhole / Kiosk Inspection Program
- Feeder Reliability Metrics
- IT Assessment
- Fleet Assessment

Strategic Investments

Strategic Investments are identified through review of performance measurements for continuous improvement. These investments are identified to maintain alignment with NPEI's strategic objectives. Considerations to identify needs typically include:

- Reliability / Performance: Investments that maintain current performance levels or enhance reliability and reduce outage occurrence / duration.
- Safety: Investments that will mitigate hazards to workers and/or will improve public safety.
- Efficiency: Investments that will result in system loss reduction and/or improved operational response.
- Community Relations: Investments that will improve NPEI's presence in the community.

Technical Alternatives

Once needs are identified, technical alternatives to addressing the need are developed. The considerations given to development of each technical alternative include impacts on reliability, safety, efficiency, and community relations. Consideration is also given to the required timing, resource and material availability.

Each technical alternative also identifies whether external factors are driving the need, for example, a road relocation with an associated time constraint. These technical alternatives typically move directly into development of a business case and are prioritized based on the required timing.

Business Cases

Business cases are developed for projects identified at the highest priority levels. The business case outlines the project scope and the expected outcome. The business case also identifies the cost associated with project execution, the category of investment, the evaluation criteria, and the associated business drivers.

NPEI's corporate business values and strategic objectives are fundamental to the drivers identified in each business case. It is imperative that the developed business case is in line with NPEI's vision and strategy and appropriately reflects the needs of the community and its customers.

Prioritize and Select Investments

Business cases are selected for execution based on priority. Business cases developed to address a need stemming from an external driver are prioritized based on deadlines and resource availability. These are typically customer, municipally, regionally, or regulatory driven.

Business cases based on internal drivers are prioritized based on the identified risk that results from asset or asset class condition assessment. The identified risk is balanced against resource availability to determine an appropriate timeline for execution. In some instances, both a strategic investment and internal driver are addressed through the implementation of a business case which will result in a higher level of prioritization.

Strategic Investment driven business cases are prioritized based on alignment to strategic objectives. Priority is based on the level of impact on: Reliability / Performance, Safety, Efficiency, and Community Relations.

Expenditure Attestation

The expenditure attestation process involves review of each proposed investment by NPEI senior management. This control measure ensures that the investment portfolio is appropriately aligned with NPEI's vision and strategic objectives. It also ensures that appropriate risk mitigation strategies are deployed within the investment portfolio.

The attestation process is iterative and allows senior management to request re-prioritization and selection of investments to achieve greater alignment to strategic objectives. Once a final investment portfolio is identified, it forms the capital business plan and becomes part of the annual capital and operating budget. The annual capital and operating budget are presented to the Finance Committee for review and approval.

Approval by Finance Committee / Board of Directors

NPEI's Finance Committee reviews the capital investment plan and consideration is given to:

- alignment with strategic goals
- mitigation of business risk
- impact on customers
- benchmark against historical expenditures

Upon approval of the capital investment plan, the capital and operating budgets are forwarded to the Board of Directors for review and approval. Once approved by the Board of Directors, the capital investment plan is moved to the work execution process.

Work Execution

The work execution plan considers project dependencies (project phasing), labour and material constraints, and externally driven deadlines. A work execution plan is presented to management staff in the Operations department at the onset of the business plan deployment.

Work execution progress is tracked by the Director of Engineering, Purchasing Manager, and the Director of Operations. Progress is tracked in a centralized database.

The open projects reports are reviewed by project stakeholders at monthly meetings to ensure adherence to the plan.

Continuous Improvement

A project close out meeting is held following the work execution phase. The meeting captures lessons learned and potential opportunities for improvement moving forward. Opportunities for improvement are reviewed by management to determine if changes to internal processes are required.

5.3.1.3 Supporting Inputs and Outputs Related to Capital Expenditure Planning

Information resulting from the following studies, assessments, and plans were used to prepare the capital expenditure plan.

2018 Asset Condition Assessment

The 2018 Asset Condition Assessment was completed by an independent consultant, Kinectrics Inc., and involved assessing the condition of assets in major asset categories of NPEI's distribution system. The following categories were included in the ACA study:

- Power Transformers
- Large Pad-mounted Transformers
- Small Pad-mounted Transformers
- Pole-top Transformers
- Wood Poles
- Concrete Poles
- Steel Poles
- Pad-mounted Switchgear
- Overhead Primary Conductors
- Underground Primary Cables

Using data from NPEI's GIS, inspection results, and maintenance activities, the ACA provides a quantitative assessment of asset condition using a health index approach. A 20-year flagged for action plan was also determined for each asset category included in the study. This ACA is an update of the ACA produced for NPEI in 2014. ACA study details are provided in Appendix .

2019 Fleet Sustainment Plan

The 2019 Fleet Sustainment Plan results are provided in Appendix F. Currently NPEI has a fleet of 63 vehicles that range in age from 2001 to 2019. Of the 63 vehicles, 28 are greater than 3 tons and 35 are less than 3 tons.

The Fleet Sustainment study analyzed existing vehicles based on inputs such as age and kilometers travelled. Each vehicle is given a weighted score which is used to prioritize replacements. The analysis results indicate the capital expenditures required to maintain a fleet compliment based on replacement of end of life vehicles.

2019 Information Technology Asset Management Strategy

Information technology expenditures ensure that business goals are aligned to technological solutions. Information technology expenditures are hardware, including network infrastructure, switches, access points, servers, equipment, PCs, tablets, laptops, printers, plotters, projectors, phone and telecommunications; software including licensing and web solutions. Beginning with a business requirement, resilient and redundant integrated and secure solutions are put into place ensuring business continuity and sustainability.

There are five areas for IT Capital Budget:

- Hardware
- Software
- Cyber security
- Training
- Resources including professional services

The requests within each of these areas allow for the following goals to be met:

- Effective and Efficient Business Processes
- Support of risk and compliance management processes and continuous lifecycle methodology
- Integrated, reliable, enterprise solutions
- Network Integration and Security
- Embedded business continuity practices, and Continued Update and testing of Incident Response Plan, Disaster Recovery plan, and Business Continuity Plan.

In 2019, an IT Assessment was completed to review all IT assets, along with future business requirements based on operational need. The IT Assessment identifies forecasted capital expenditures from 2020 to 2025 for hardware and software components necessary to achieve NPEI's technology deployment strategy.

The IT Assessment set out the 5 year plan for IT renewal based on the age, support, use of the existing network infrastructure, and alignment to NPEI Written Information Security Program (WISP). NPEI has invested in building and maintaining a network composed of both physical and virtual environments. All solutions are maintained to ensure full use of a solution while ensuring that support is available on a product. Investments in IT Assets are considered in the following areas:

- Hardware and affiliated Appliances
  - Network switches and infrastructure
  - Servers:
    - Physical servers
    - Hyper converged Virtual IT infrastructure
  - Office Tools and Appliances
  - Desktop PC’s and Monitors
  - Laptops
  - Mobile Workforce Tools and Appliances
  - Laptops, Tablets
  - Telecommunications
  - Backup hardware and infrastructure
- Software Applications
- Cyber Security

Each area of the network was assessed on age, support available, use, security and cost. Annually, solutions are reviewed to determine how vendors are evolving the product and how future enhancements and functionality are made available, and whether roadmap of a product continues to meet the business requirement.

Feeder Reliability Assessment

Since 2012, NPEI has leveraged OMS data to assess the performance of distribution feeders. Individual feeder performance indices are provided in Appendix of this document. Trends in poor performing feeders are identified by analysing year to year performance which drives capital expenditures in the system service category. The data is used to identify opportunities to reduce feeder exposure, improve sectionalizing capability, and to add supply redundancy to better reliability.

5.3.2 Overview of Assets Managed

5.3.2.1 Description of Service Area Features

NPEI's electrical distribution system services the municipalities and townships of Fonthill, Niagara Falls, Lincoln and West Lincoln. As the local electrical distribution company, NPEI services approximately 55,434 residential, general service, and street-light customers.

The following map illustrates the extent of NPEI's service area:

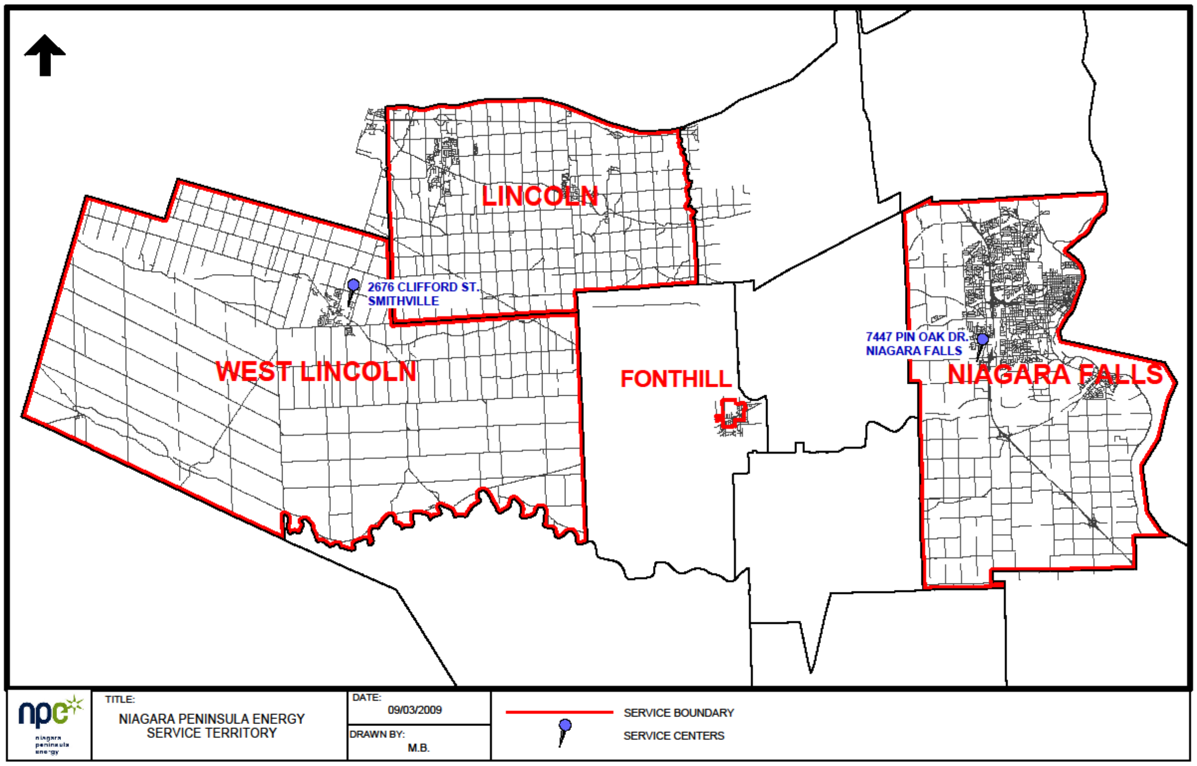


Figure 5- 25: Service Area Map

The Western portion of NPEI's service territory is substantially rural and includes the Township of West Lincoln and the Town of Lincoln. The administrative centre of West Lincoln is the community of Smithville, though the township comprises the communities of Abingdon, Allens Corner, Attercliffe, Basingstoke, Bismark, Boyle, Caistor Centre, Caistorville, Elcho, Fulton, Grassie, Kimbo, Port Davidson, Rosedene, Silverdale, Smithville, St. Anns, Vaughan, Warner, Wellandport, Wilcox Corners and Winslow. The administrative centre of the Town of Lincoln is in the community of Beamsville, though the town comprises the communities of Vineland, Jordan, Campden, Tintern, and Rockway.

The distribution system covers the limits of Lincoln and West Lincoln townships. Approximately 16,203 (December 2018) customers are serviced in Lincoln and West Lincoln. Electricity is supplied to customers in these areas via the following substations:

Table 5- 17: Lincoln / West Lincoln - Transformer Stations

Transformer Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Beamsville TS	Hydro One	115kV	27.6kV	4
Niagara West TS	Niagara West Transformer Corporation	230kV	27.6kV	3
Vineland DS	Hydro One	115kV	27.6kV	2

There are four distribution substations connected to the 27.6kV system to service customers from the 8.32kV distributions system:

Table 5- 18: Lincoln / West Lincoln - Distribution Stations

Distribution Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Bismark DS	Hydro One	27.6kV	8.32kV	3
Campden DS	Niagara Peninsula Energy	27.6kV	8.32kV	2
Greenlane DS	Niagara Peninsula Energy	27.6kV	8.32kV	2
Smithville DS	Niagara Peninsula Energy	27.6kV	8.32kV	2

The Eastern portion of NPEI's service territory consists of the City of Niagara Falls and has a significant urban component with a high traffic tourism core. The Southern and Western portions of the City of Niagara Falls are primarily rural.

Approximately 38,287 customers (December 2018) are serviced in the City of Niagara Falls. Electricity is supplied to customers in the city via the following substations:

Table 5- 19: Niagara Falls - Transformer Stations

Transformer Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Murray TS	Hydro One	115kV	13.8kV	16
Kalar TS	Niagara Peninsula Energy	115kV	13.8kV	8
Stanley TS	Hydro One	115kV	13.8kV	10

There are eleven distribution substations connected to the 13.8kV system to service customers from the 4.16kV distributions system:

Table 5- 20: Niagara Falls - Distribution Stations

Municipal Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Allendale MS (#8)	Niagara Peninsula Energy	13.8kV	4.16kV	3
Armoury MS (#1)	Niagara Peninsula Energy	13.8kV	4.16kV	4
Dorchester MS (#23)	Niagara Peninsula Energy	13.8kV	4.16kV	3
Drummond MS (#10)	Niagara Peninsula Energy	13.8kV	4.16kV	3

Lewis MS (#7)	Niagara Peninsula Energy	13.8kV	4.16kV	4
Margaret MS (#14)	Niagara Peninsula Energy	13.8kV	4.16kV	3
Ontario MS (#3)	Niagara Peninsula Energy	13.8kV	4.16kV	2
Park MS (#6)	Niagara Peninsula Energy	13.8kV	4.16kV	4
Swayze MS (#18)	Niagara Peninsula Energy	13.8kV	4.16kV	3
Virginia MS (#17)	Niagara Peninsula Energy	13.8kV	4.16kV	4

At the center of NPEI's service territory is the village of Fonthill which is a portion of the Town of Pelham. The distribution system covers the urban limits of Fonthill only, servicing approximately 1,535 (December 2018) customers. Electricity is supplied to customers in these areas via the following substations:

Table 5- 21: Fonthill - Transformer Stations

Transformer Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Allanburg TS	Hydro One	115kV	27.6kV	2

There are two distribution substations connected to the 27.6kV system to service customers from the 4.16kV distributions system:

Table 5- 22: Fonthill - Distribution Stations

Distribution Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Pelham DS	Niagara Peninsula Energy	27.6kV	4.16kV	2
Station DS	Niagara Peninsula Energy	27.6kV	4.16kV	3

The following table summarizes features and associated data related to NPEI's service area:

Table 5- 23: NPEI Distribution System Features

System Feature	Data
2019 Peak Demand	251.1 MW
Number of Customers	56,025
Service Territory	827 sq. km
Transformer Stations Supplying NPEI	7
Number of TS Feeders	48
Distribution Stations Supplying NPEI	17

Number of DS Feeders	49
Overhead Line Route Length	1,454.6 km
Underground Cable Route Length	586.2 km

NPEI's service territory is located in the heart of Niagara Region, with a very diverse economy. The service territory consists of traditional agricultural areas including livestock, grains, tender fruit, vegetables, nurseries and flowers. There are numerous wineries, craft breweries and distilleries, as well as heritage sites and natural attractions such as the Niagara Escarpment, Niagara Falls and Lake Ontario.

NPEI's service territory also includes several vibrant urban centres, with the largest being the City of Niagara Falls. The Niagara Region is a high traffic tourist area with over 12 million visitors per year.

Niagara Region lies between Lakes – Erie to the South and Ontario to the North – and is considered to be a moderate climate zone. Because the two bodies of water moderate the area's temperatures, the Niagara Region is ideal for tender fruit growing. Also, its long warm-weather season makes it near perfect for such outdoor activities as golf, cycling and boating.

By mid-April, the Niagara Region can enjoy temperatures well over 12°C, with temperatures warming up rapidly by mid-May. The long, warm summer can continue well into September. Mid-summer is punctuated by mild fluctuations of temperatures with short periods of humid days that can reach into the 30's°C. But the average mid-summer temperature is usually in the high 20's°C. Autumn, sets in gradually and is often considered to be the most enjoyable season of the year in Niagara.

The sun shines in the region between 1,800 and 2,000 hours annually, with December being the greyest month.

Uniform precipitation is expected throughout the year, with no remarkable periods of wet or dry peaks. Winter snowfall is usually minimal, with the odd snowstorm setting in and temperatures rarely reach below 0°C. Forty inches or less of snowfall is standard in the Niagara Region. With milder winter temperatures, precipitation can turn to rain even in December and January.

NPEI has the following neighbouring utilities; Alectra, Hydro One, Niagara-on-the-Lake Hydro, Canadian Niagara Power, Welland Hydro and Grimsby Power.

5.3.2.2 NPEI Asset Profile

NPEI's key distribution asset categories are identified in Table 5-24. The table includes population, average age, and health index distribution for the asset category.

Table 5- 24: Asset Categories, Health Index, and Average Age

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age	Average DAI	Age Availability
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)			
Power Transformers		20	20	77%	1	0	3	8	8	27	61%	100%
Pad-Mount Transformers - Large		74	74	95%	0	0	3	6	65	15	43%	100%
Pad-Mount Transformers - Small		3391	3369	96%	0	14	57	68	3230	17	57%	99%
Pole-Mount Transformers		6077	6051	74%	677	574	831	866	3103	25	96%	87%
Poles - NPEI Owned	Wood	23830	23733	81%	1042	1944	1807	3523	15417	33	88%	98%
	Concrete	621	618	91%	2	13	4	85	514	29	88%	98%
	Steel	371	370	95%	0	0	0	1	369	20	92%	100%
Poles - Non NPEI Owned	Wood	7053	6841	91%	98	148	80	557	5958	13	85%	25%
	Concrete	5719	5690	95%	2	10	24	143	5511	8	79%	35%
	Steel	680	646	96%	0	0	0	13	633	7	63%	52%
Pad-Mount Switchgear		170	61	92%	0	1	1	3	56		35%	0%
Underground Cables *		570.9	433.5	95%	3.8	10.8	9.3	18.5	391.0	13	0%	76%
Overhead Lines *		1451.7	558.0	100%	0.0	0.0	0.0	0.1	557.9	3	0%	38%

* by length (km)

Figure 5-26, shown below, indicates that power transformers, wood poles, pole-top transformers and underground cables have the highest percentage of units in poor condition. These health indexes directly tie to several system renewal capital expenditures aimed at asset replacement.

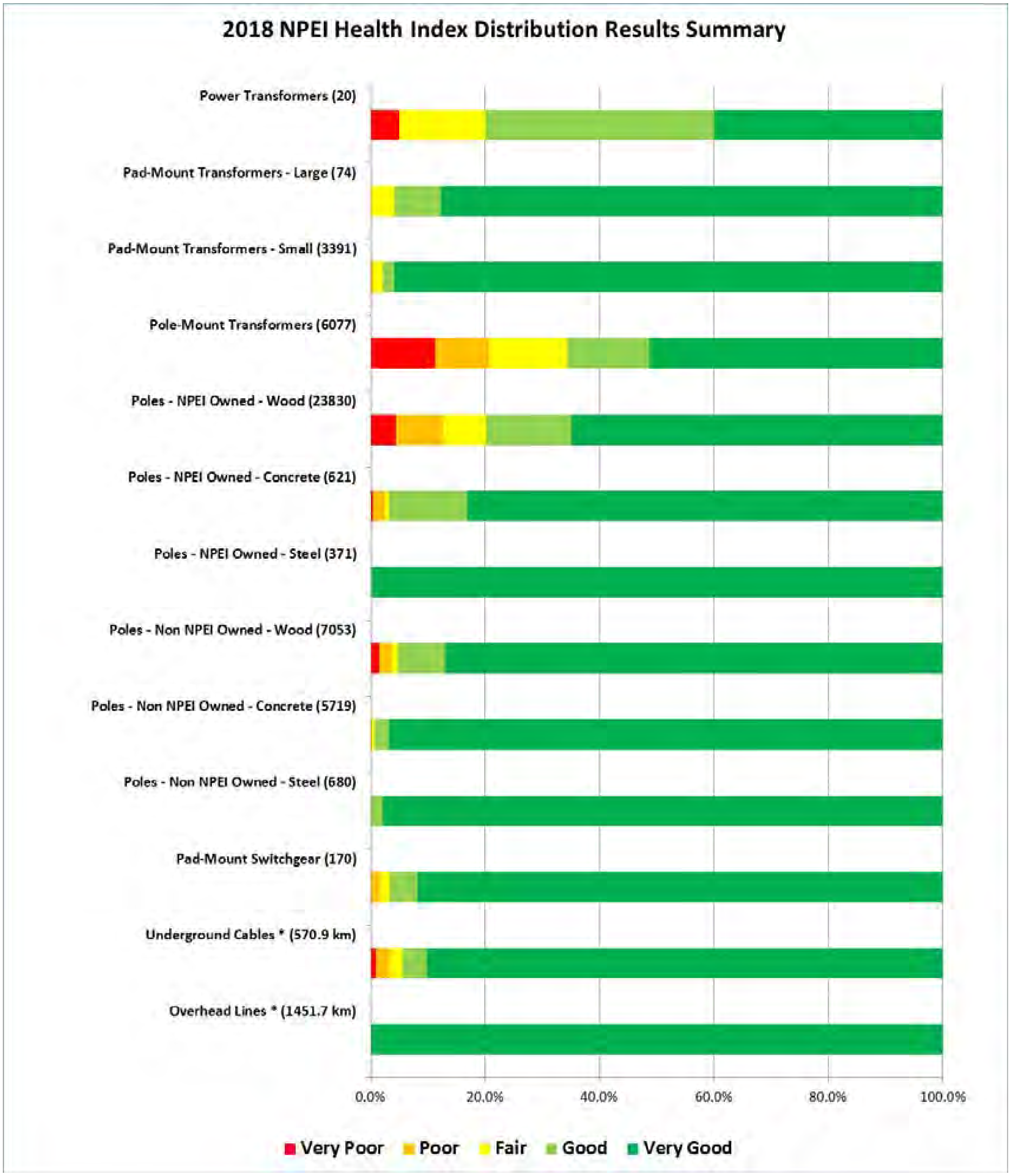


Figure 5- 26: 2018 Health Index Distribution

It is evident that NPEI owned wood poles, pole mounted distribution transformers, and underground primary cables are asset classes that have a larger portion of the asset's condition being Very Poor. The remaining assets exhibit a condition degradation pattern that can be expected of a mature utility and require periodic system renewal to mitigate additional failure risks of assets. The ACA report, found in

Appendix F, also provides a recommended levelized replacement plan. The replacement plan is used as a preliminary baseline for NPEI on how many assets should be replaced to maintain the overall system health. The baseline does not consider external factors such as load growth, customer preference, external stakeholders or improvement in reliability measures. The baseline is primarily used as an initial approximation analysis for NPEI to understand the level of investment needed to maintain the current level of asset condition.

NPEI Owned Wood Poles

NPEI owns 23830 wood poles. Figure 5-27 presents the age demographics of these poles and Figure 5-28 shows their Health Index Distribution. The average Health Index for this asset group, based on age and field inspections, is 81%. Approximately 12% of the poles were calculated to be in very poor to poor condition.

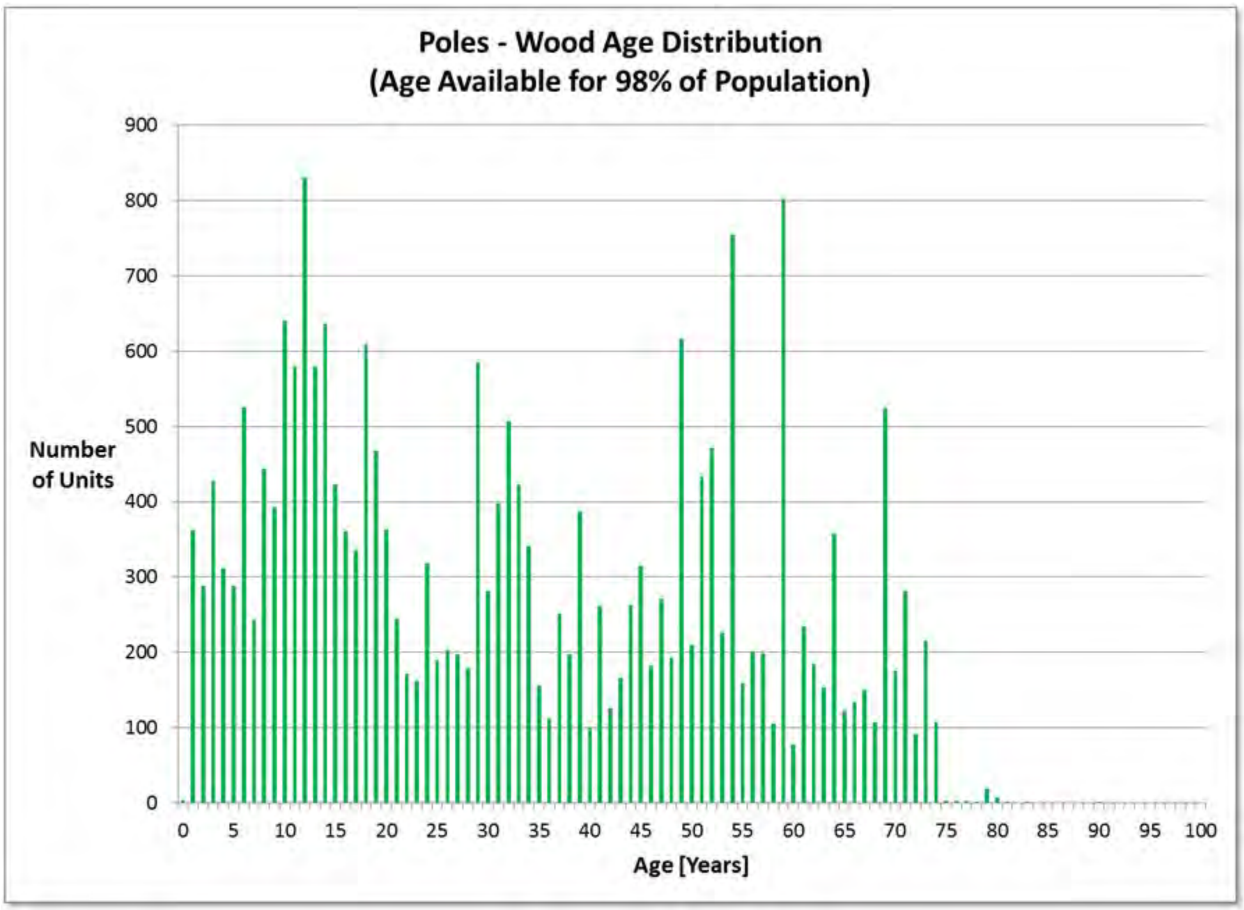


Figure 5- 27: 2018 NPEI Owned Wood Pole Age Distribution

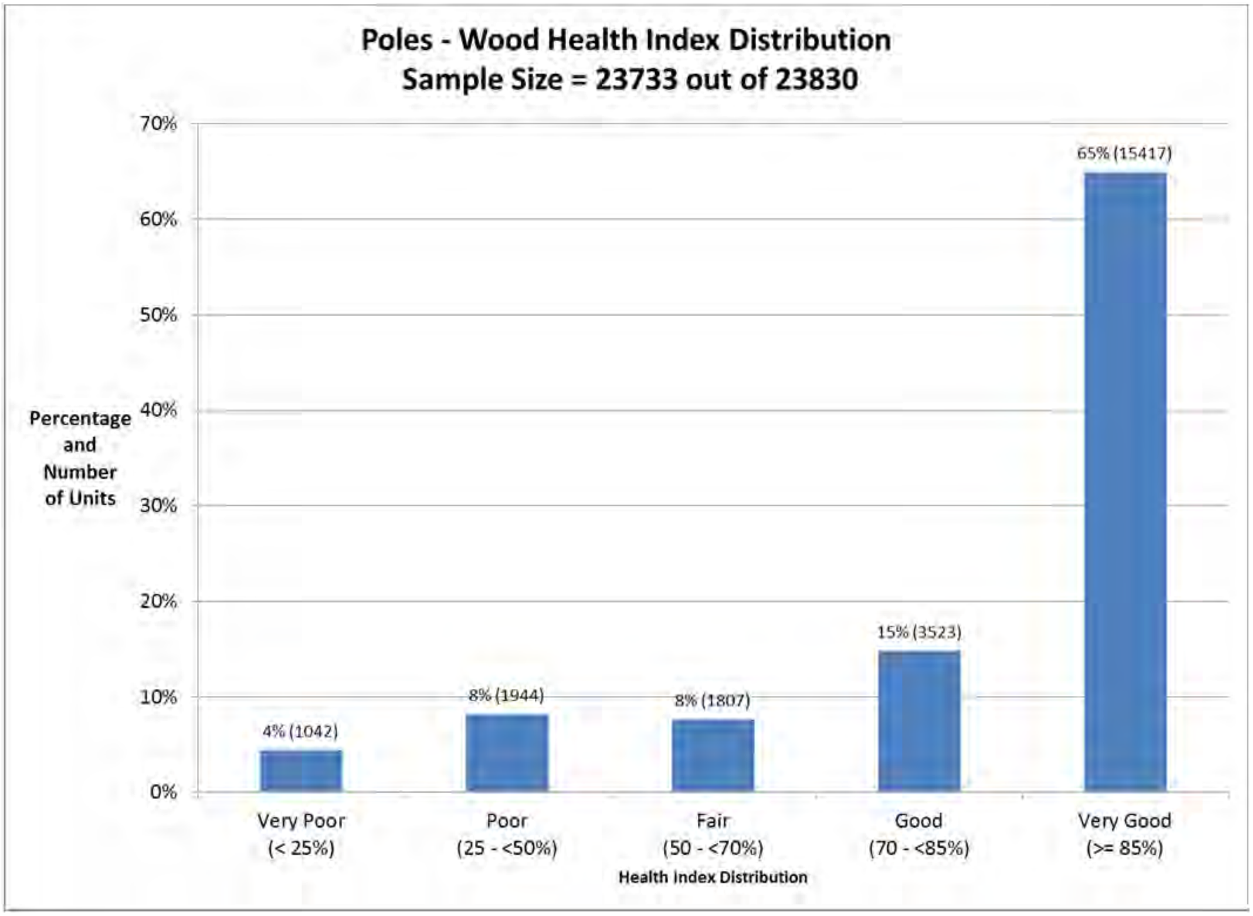


Figure 5- 28: 2018 NPEI Owned Wood Pole Health Index Distribution

Pole Mounted Distribution Transformers

NPEI has 6077 pole mounted distribution transformers in service. Figure 5-29 presents the age demographics of these transformers and Figure 5-30 shows their Health Index Distribution. The average Health Index for this asset group, based on age and loading, is 74%. Approximately 20% of the units were found to be in very poor to poor condition.

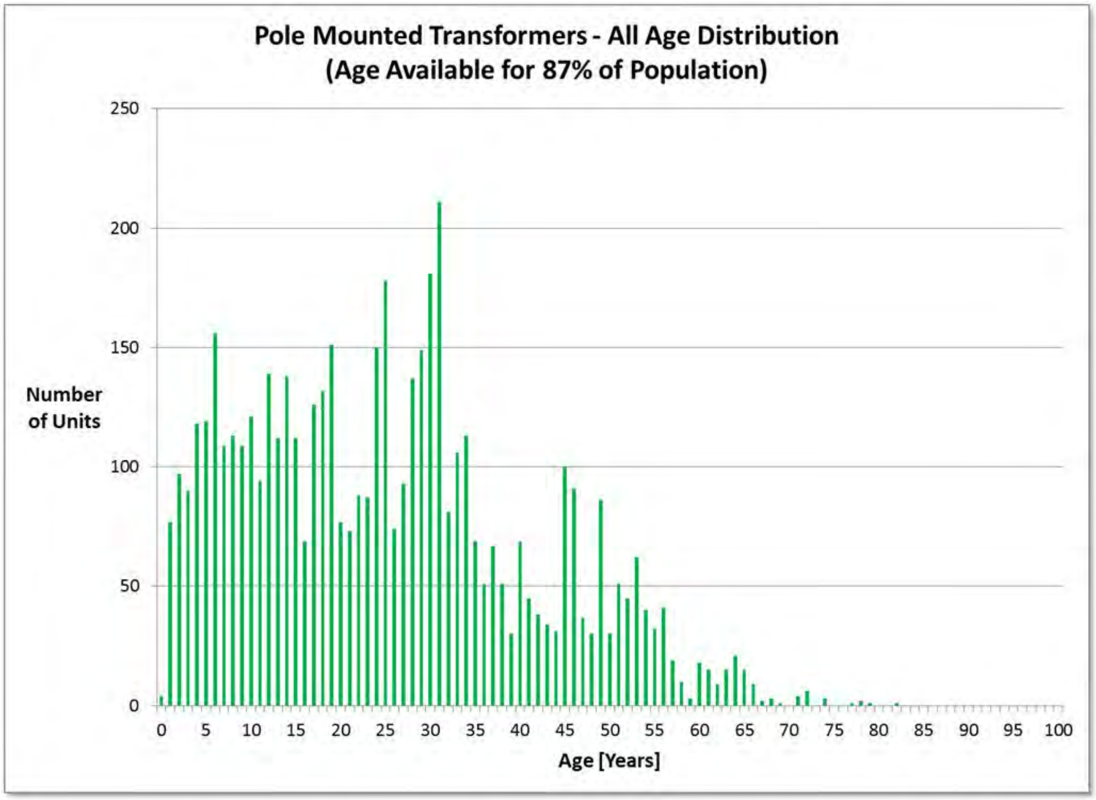


Figure 5- 29: 2018 Pole Mounted Transformer Age Distribution

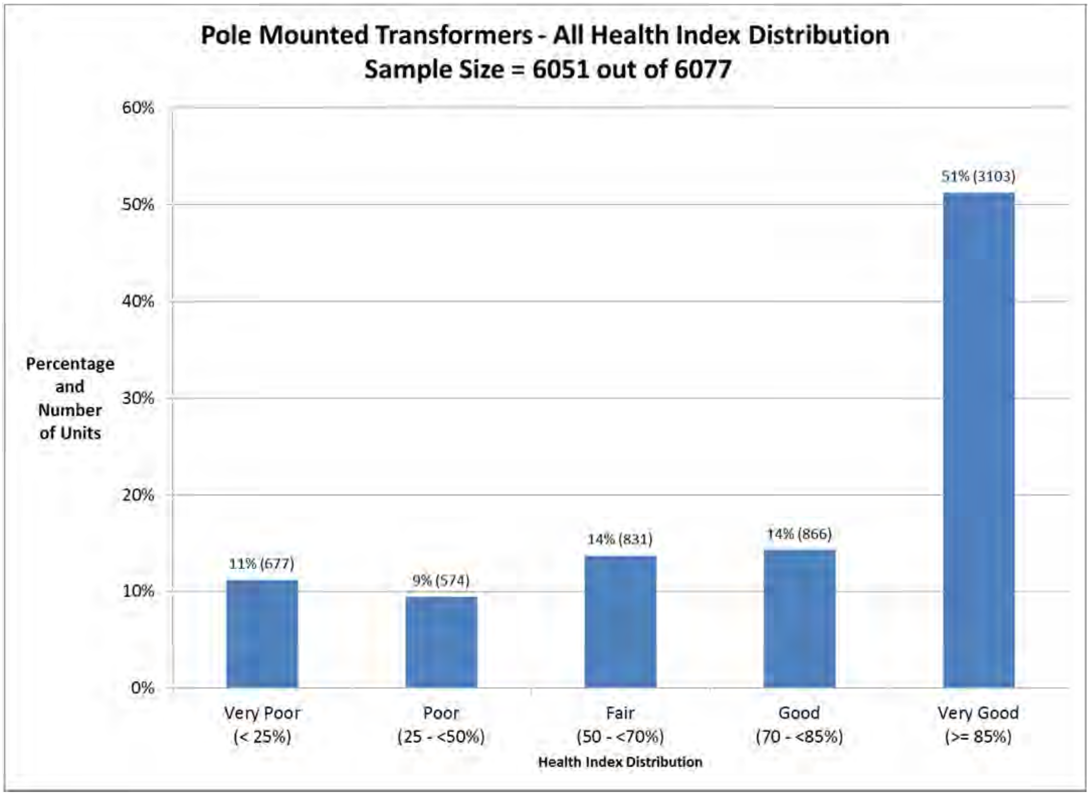


Figure 5- 30: 2018 Pole Mounted Transformer Health Index Distribution

Underground Primary Conductors

NPEI has 570 km of primary underground conductor in service. Figure 5-31 presents the age demographics of these conductors and Figure 5-32 shows their Health Index Distribution. The average Health Index for this asset group, based on age, is 95% per conductor-km. Approximately 3% of the conductor-km's were found to be in very poor to poor condition.

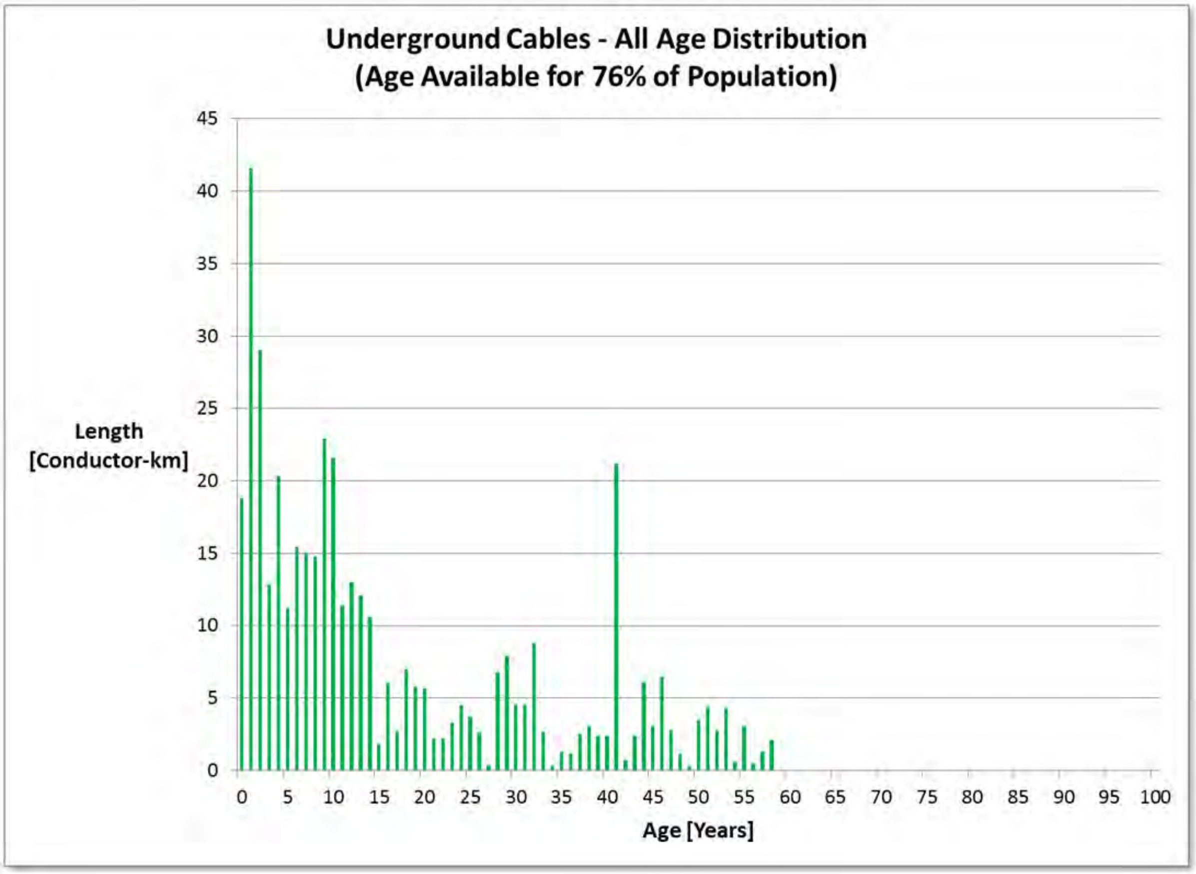


Figure 5- 31: 2018 Underground Primary Conductor Age Distribution

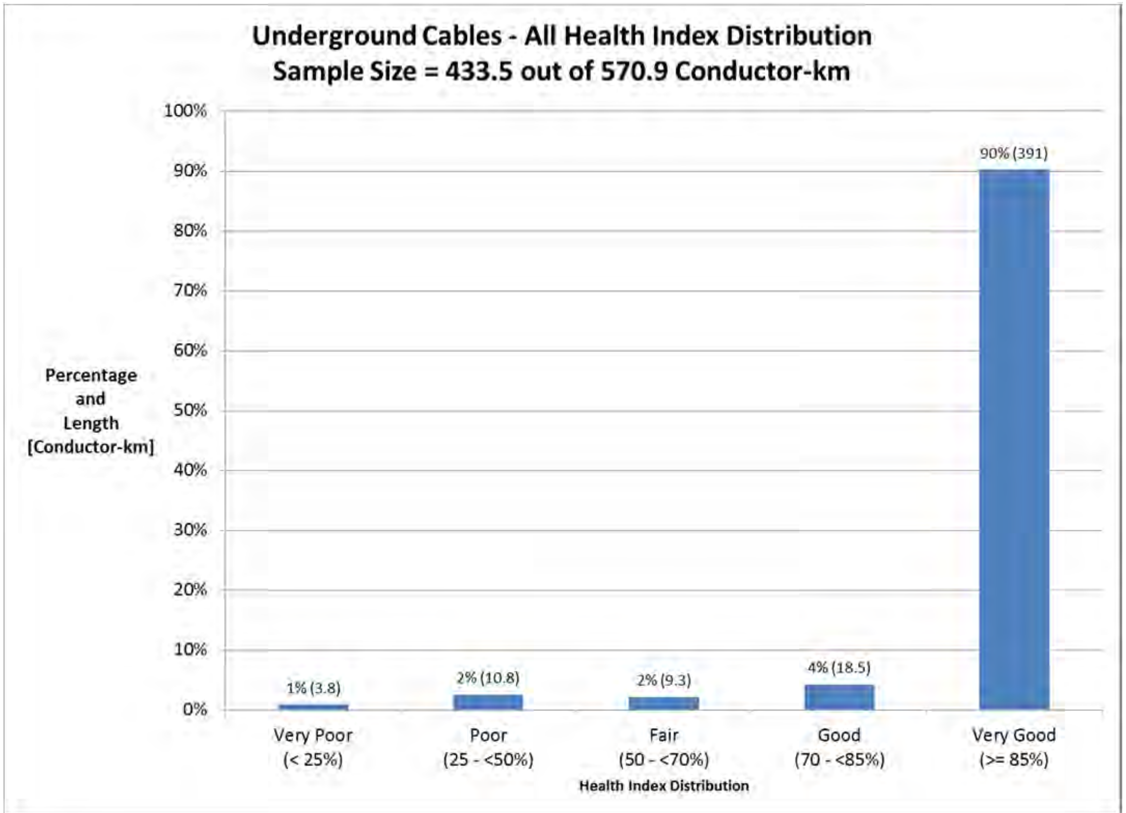


Figure 5- 32: 2018 Underground Primary Conductor Health Index Distribution

5.3.2.3 Assessment of System Capacity

Station Capacity

NPEI's distribution system is supplied from seven separate transformer stations. All are owned and operated by Hydro One with the exception of Niagara West TS and Kalar TS. Niagara West TS is owned by Grimsby Power Inc., Kalar TS is owned and operated by NPEI.

For planning purposes, Transformer Stations (TS) can be loaded up to 100% of nameplate of a single transformer. For contingency purposes, there is a 60-day overload capacity of approximately 120% for at least two hours a day. This will allow enough time for a worst-case transformer failure requiring the replacement of the transformer.

Municipal Stations (MS) are planned, configured and loaded to 100% normal rating. There are currently sufficient 4.16kV feeder interconnections that allow for an entire MS to be backed up from one or more adjacent MS. A municipal station transformer should not be loaded above its normal rating during non-contingency situations. Operating above normal rating will result in a shortening of the transformer service life. Under contingency situations load is to be transferred to other municipal stations, without exceeding the normal rating of the municipal station transformers or circuits receiving the load, as soon as possible.

Distribution Stations (DS) are planned, configured and loaded to 100% normal rating. There are currently insufficient 8.32kV feeder interconnections to allow for an entire DS to be backed up from one or more adjacent DS. For this purpose, NPEI owns and maintains a portable DS, which allows for connection of the outgoing feeders at the DS locations. This portable DS allows NPEI to isolate and de-energize the distribution station for maintenance or repairs as needed. A distribution station transformer should not be loaded above its normal rating during non-contingency situations. Operating above normal rating will result in a shortening of the transformer service life. Under contingency situations load is to be transferred to other distribution stations, without exceeding the normal rating of the distribution station transformers or circuits receiving the load, as soon as possible.

The following table summarizes the nameplate rating of each of these transformer stations and the peak load from 2019.

Table 5- 25: Transformer Station Capacity

Delivery Point	Service Area	Rating (MVA)	Maximum Load MVA (2019)
Allanburg TS	Fonthill	9.6	5.2
Beamsville TS	Lincoln/West Lincoln	25/41.6	38.5
Kalar TS	Niagara Falls	22.5/30/37.5	42.4
Murray TS	Niagara Falls	67.5/90/112.5	91.5
Niagara West TS	Lincoln/West Lincoln	40/53.2/63.4	39.9
Stanley TS	Niagara Falls	40/53.3/66.7	60.4
Vineland DS	Lincoln/West Lincoln	15/20/25	20.9

In addition, NPEI utilizes the GIS data for new connections and is able to report on and evaluate new connections, or system growth, based on both the station and individual feeder supplying the new connections. This allows NPEI to monitor which sections of their distribution system are experiencing the most concentrated growth. Figure 5-33 below shows the concentration of new connections or system growth over the Historical period by TS and feeder.

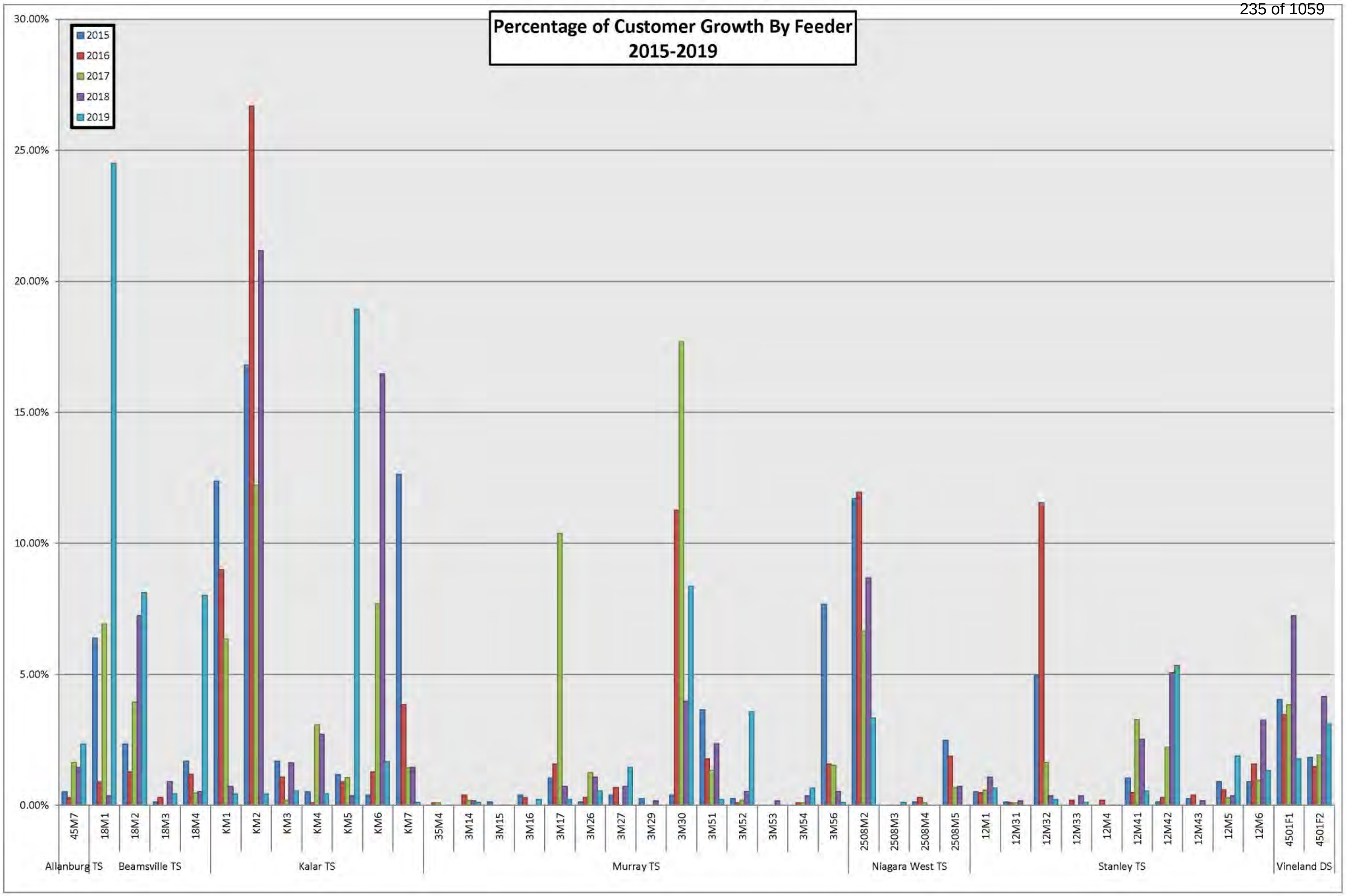


Figure 5- 33: Percentage of Customer Growth by Feeder

The Fonthill area is serviced by 2 feeders from Allanburg TS. One of the feeders normally supplies all of the load. A backup feeder is available from the TS during contingencies. Historical peak load values have not encroached on the available capacity from the Allanburg TS supply feeders.

The Lincoln and West Lincoln areas are serviced by Beamsville TS, Niagara West TS, and Vineland DS. Niagara Peninsula Energy and Grimsby Power Inc. both utilize the Beamsville TS and Niagara West TS supply points. Historical peak load values are within the nameplate rating capacity for each of the available supply points, however, the peak loads are approaching the upper limits at both Beamsville TS and Vineland DS. NPEI is monitoring load growth in the Lincoln and West Lincoln areas and developing contingency plans to accommodate the anticipated load growth. Load transfer capability exists between the 3 supply points to manage load growth resulting in an overall availability of capacity at this time.

The Niagara Falls area is serviced by Kalar TS, Murray TS, and Stanley TS. Historical peak demand on Murray TS is within the second stage cooling rating. The historical peak load on Stanley TS is approaching the second stage cooling nameplate rating. Both of these transformer stations are owned and operated by Hydro One. Historical peak demand on Kalar TS has recently exceeded the second stage cooling rating of the station. Kalar TS is owned and operated by NPEI. Load transfer capability exists between the 3 transformer stations in the Niagara Falls area to manage available capacity. Kalar TS was commissioned in 2004 and was designed with the capability of connecting a second set of power transformer windings and a second switchgear line-up. Installation and connection of the second line-up would result in an additional 37.5 MVA capacity at the second stage cooling rating. Niagara Peninsula Energy does anticipate the addition of the second line-up in the 2020 to 2025 forecast period.

Feeder Capacity

The majority of load is supplied through the 27.6kv and 13.8kv feeder systems. The 2019 feeder utilization statistics are shown below. From time to time, loads are transferred from one feeder to another to facilitate planned and emergency work. This may impact the individual feeder peak load that is recorded on the day of the system peak.

As part of NPEI design and operating philosophy, 13.8kV and 27.6kV feeders are loaded to 50% of capacity to ensure that contingency situations can be addressed with the minimal amount of service interruption to the customer. Feeder loading is collected and reviewed on an ongoing basis via the SCADA system. The feeder loading indicates the effectiveness of NPEI’s asset utilization planning and contingency capability.

NPEI feeders have a thermal capacity of 600A. The loading of feeders is monitored and a Planning Ampacity of 400A is used to determine if additional feeder capacity or feeder reconfiguration is required. The rationale for the 400A is to allow each feeder to have the capability of carrying additional load from another feeder during contingencies.

Table 5- 26: Transformer Station Feeder Capacity

	Feeder	Planning Ampacity	Blue Phase		Red Phase		White Phase	
			Amps	% Utilization	Amps	% Utilization	Amps	% Utilization
Beamsville TS	M1	400	236	59%	258	65%	260	65%
	M2	400	273	68%	249	62%	251	63%
Kalar TS	M1	400	260	65%	207	52%	240	60%
	M2	400	294	74%	279	70%	258	65%
	M3	400	314	79%	278	70%	243	61%
	M4	400	314	79%	289	72%	263	66%
	M5	400	84	21%	90	23%	67	17%
	M6	400	100	25%	131	33%	139	35%
	M7	400	363	91%	433	108%	342	86%
	M8	400	0	0%	0	0%	0	0%
Murray TS	M14	400	228	57%	228	57%	256	64%
	M15	400	174	44%	160	40%	168	42%
	M16	400	230	58%	234	59%	246	62%
	M17	400	347	87%	295	74%	267	67%
	M18	400	235	59%	238	60%	249	62%
	M26	400	297	74%	298	74%	316	79%
	M27	400	451	113%	340	85%	307	77%
	M28	400	133	33%	134	33%	139	35%
	M29	400	343	86%	348	87%	363	91%
	M30	400	338	85%	286	71%	267	67%
	M51	400	402	100%	389	97%	382	95%
	M52	400	167	42%	172	43%	155	39%
	M53	400	319	80%	335	84%	347	87%
	M54	400	121	30%	145	36%	148	37%
	M55	400	194	48%	191	48%	201	50%
	M56	400	226	57%	238	59%	236	59%
Niagara West TS	M2	400	217	54%	132	33%	154	39%
	M3	400	293	73%	296	74%	353	88%
	M4	400	182	46%	210	53%	159	40%
	M5	400	143	36%	157	39%	153	38%
Stanley TS	M1	400	297	74%	278	70%	245	61%

	M31	400	195	49%	197	49%	265	66%
	M32	400	270	67%	270	67%	328	82%
	M33	400	340	85%	295	74%	220	55%
	M4	400	138	34%	144	36%	214	54%
	M41	400	241	60%	331	83%	216	54%
	M42	400	218	55%	178	45%	178	45%
	M43	400	145	36%	115	29%	82	21%
	M5	400	356	89%	233	58%	252	63%
	M6	400	302	75%	373	93%	263	66%

	Feeder	Planning MW	Power		
			MW	MVA	% Utilization
Vineland DS	F1	12.5	10.902	11.6849	87%
	F2	12.5	7.1248	7.6019	57%

With the exception of the Kalar TS – M7, Murray TS – M27 and Murray TS – M51 feeders, the 27.6kV and 13.8kV peak feeder loading is well within the normal planning loading limits at the time of system peak in 2019. The Kalar Ts – M7 and Murray TS – M27 & M51 feeders are being reviewed for possible load balance or reconfiguration to shift a portion of the load to adjacent feeders.

5.3.3 Asset Lifecycle Optimization

NPEI's asset management strategies focus on maximizing the service life of distribution assets at the lowest lifecycle cost of ownership. The information gathered from asset assessments is used to determine a course of action with respect to the asset and can be a contributor to the asset renewal portion of the annual capital expenditures.

The DSP has been prepared with a vision of sustaining the assets such that they continue to perform at the present level or better in regard to safety and reliability performance while improving cost effectiveness. For each asset type, sustainment options such as increased maintenance, proactive and reactive replacement, and elimination/substitution are considered and evaluated. The option selected for each asset type reflects the assessment of risk and total lifecycle cost. The condition and performance of the assets are carefully monitored so that adjustments can be made to the sustainment plan to ensure safety, reliability and cost effectiveness are not compromised.

5.3.3.1 Asset Replacement Practice

Management of assets is specific to the asset with respect to its operating context and which refurbishment approach can be employed. In general, NPEI’s asset management practices aim to determine and mitigate the risk of operating aged assets.

If the assessment of the asset does not warrant further action, aside from future inspection, the asset can be left in service. Where the assessment of the asset identifies the need for further attention, NPEI plans and takes corrective actions. The output of asset condition assessments forms a part of the annual capital budget and prioritizing capital renewal expenditures for rehabilitation or replacement. The result is a prioritized list of detailed capital projects for the next year and a five-year capital plan that will preserve and/or enhance the value of service to the customer.

The timing of the System Renewal investments with respect to assets is often considered from a combination of a condition-based assessment, safety issues, probability and consequence of failure and the asset approaching the end of its' economic useful life. NPEI strives to achieve an optimal renewal investment by addressing those assets that have a much larger impact of failure or pose a safety concern.

Assets Flagged for Action

Figure 5-33 illustrates the 20 year "flagged for action" plan that resulted from the 2018 ACA. This plan is the basis for NPEI's system renewal based investments for assets with both proactive and reactive replacement strategies.

Asset Category		Flagged for Action Plan by Year																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Power Transformers		1	0	0	0	0	0	0	0	1	2	4	3	1	3	2	0	1	0	0	0
Pad-Mount Transformers - Large		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pad-Mount Transformers - Small		13	14	15	16	16	16	18	19	20	21	21	22	23	24	26	26	27	28	30	30
Pole-Mount Transformers		377	290	288	288	288	288	288	288	116	116	116	111	111	111	111	111	111	111	110	110
Poles - NPEI Owned	Wood	968	726	726	726	726	726	726	726	208	207	188	188	188	188	188	188	188	188	188	188
	Concrete	6	5	4	4	3	3	3	2	2	3	3	3	3	3	4	4	4	4	4	4
	Steel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Poles - Non NPEI Owned	Wood	86	66	66	66	66	66	66	66	32	32	32	32	32	32	32	32	32	32	32	32
	Concrete	10	9	8	7	6	6	6	6	6	6	7	7	7	8	8	8	8	8	8	8
	Steel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pad-Mount Switchgear		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Underground Cables *		15.0	15.0	15.0	15.0	12.0	4.0	5.0	4.0	4.0	4.0	5.0	4.0	5.0	5.0	5.0	5.0	6.0	6.0	6.0	5.0
Overhead Lines *		0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.6	0.7	1.0	1.1	1.8	1.9	2.1	2.4	2.9

* by length (km)

Figure 5- 34: 20 Year Levelized Flagged for Action Plan

Asset categories are managed by either proactive or reactive replacements. Table 5-27 summarizes the asset management strategies for each category. Assets that have a low consequence of failure vs. a high cost of replacement are generally managed through a reactive approach.

Table 5- 27: Asset Management Strategy by Category

Asset Category	Replacement Strategy
Power Transformers	Proactive
Large Pad-mounted Transformers	Proactive/Reactive
Pole-Top Transformers	Proactive/Reactive
Wood Poles	Proactive
Standard Pad-mounted Transformers	Proactive/Reactive
Pad-mounted Switchgear	Proactive
Underground Cables	Proactive/Reactive
Kiosk Enclosures	Proactive

Assets that have a high consequence of failure such as station power transformers, poles, switchgear, etc. are managed through proactive replacement programs. The levelized flagged for action plan identifies the annual quantities of asset that require attention to keep pace with assets at end of service life. The annual quantities are the basis for the identified annual expenditure levels in the capital program for the forecast period.

For example, the levelized flagged for action plan indicates that approximately 726 poles should be replaced in 2021. In structuring the pole replacement strategy for 2021, NPEI reviewed the prioritized list of pole integrity deficiencies resulting from cyclical inspections. Areas with a high concentration of pole deficiencies are identified as targets for wholesale system renewal rather than individual change-outs. The decision to perform a wholesale rebuild is deemed to be more efficient when the area encompasses distribution transformers also at or near end of life and where system capacity and loss reduction benefits can also be realized. The balance of prioritized poles is scheduled for change out under the recurring project for pole replacements.

Flagged for Action Considerations

There are several options available to NPEI to manage assets that have been flagged for action. These are:

- Replacement
- Refurbishment/retrofit
- Run to failure strategy

Replacement

For certain assets such as power transformers, a proactive replacement strategy is utilized. This is based on the fact that the asset is a critical component necessary to maintain the security and reliability of NPEI's supply. The consequence of asset failure outweighs the cost associated with replacement.

Another application is to proactively replace a cluster of assets based on the results of an asset condition assessment or at the time that the first asset begins to fail. This is more expensive in the short term but allows for technological upgrades, completing all work in the area at once and causing a single disruption for customers while conducting the work. This approach is often used with localized area rebuild projects.

Refurbishment

In some situations, refurbishment is a lower cost alternative to replacement and can mitigate the risk and likelihood of asset failure. The decision to refurbish an asset vs. replacement is made at various levels where it is identified that the total lifecycle cost of the asset can be minimized. For example, for pad-mounted transformers, the inspector will identify whether the condition of the enclosure is such that it can be re-furbished. As indicated in, Table 5-27 NPEI refinishes pad-mounted equipment annually as part of cyclical maintenance programs.

Run to Failure

In some cases, a run to failure strategy is utilized resulting in a reactive replacement strategy. An asset is run to failure when the replacement cost does not outweigh the consequence of failure. In these cases, NPEI has an appropriate level of resource availability to manage the replacement effort in a timely manner.

Essentially, every asset can be run to failure. This is usually less expensive for short-term planning and maximizes the financial value of the asset. However, it becomes inefficient to manage returning to the location to replace each asset as it fails. This method also tends to entail a 'like for like' replacement rather than upgrading technology, which may not always provide opportunities for upgrade of the utility's capabilities.

Reactive asset management relates more to equipment that does not get more than a visual inspection and includes:

- Conductor and Cable
- Distribution Transformers
- Pole Line Hardware
- Metering Equipment

5.3.3.2 Maintenance and Inspection Practices Overview

NPEI employs preventative and predictive maintenance practices relating to specific assets to ensure the assets are operating as intended and the risk of failure is minimized, or otherwise identified and monitored. An evidence-based maintenance program is essential to the safe and reliable delivery of electricity to customers. The preventative maintenance programs employed by NPEI are performed to regulated requirements, include staff and/ or qualified contractors, and may include specific industry standards and manufacturer specifications.

Inspection and testing results are reviewed by NPEI engineering staff and resulting deficiency records are associated with assets in the GIS. Deficiencies that require immediate corrective action are remedied through issuance of a work order. The remaining deficiencies are prioritized based on the likely-hood of asset failure and the outcome associated with the failure. For example, a pole identified as "replace in 1 to 5 years" with a high consequence of failure will rank higher than a pole identified as "replace immediate" with a low consequence of failure.

NPEI utilizes cyclical inspection programs that align with the requirements of Appendix C of the DSC. The results from these inspections are recorded in the GIS database and utilized as inputs to the Asset Condition Assessment (ACA) process:

Table 5- 28: Inspection Cycles

Asset Category	Activity Type	Description	Frequency
Power Transformers	Inspection	Visual Inspection	Monthly
	Testing	DGA, Oil Analysis, Furan	Annually
	Maintenance	Electrical Integrity Tests, Surface Refinishing	Every 3 Years
Large Pad-mounted Transformers	Testing	DGA, Oil Analysis, Furan	Annually
	Inspection	Visual, Infrared, Ultrasonic	Every 3 Years Urban, 6 Years Rural
	Maintenance	Surface Refinishing	Result from Visual Insp.
Pole-Top Transformers	Inspection	Visual Inspection	Every 3 Years Urban, 6 Years Rural
Wood Poles	Inspection / Maintenance	Visual Inspection, Treatment	Every 3 Years Urban, 6 Years Rural
Standard Pad-mounted Transformers	Inspection	Visual, Infrared, Ultrasonic	Every 3 Years Urban, 6 Years Rural
	Maintenance	Surface Refinishing	Result from Visual Insp.
Pad-mounted Switchgear	Inspection	Visual, Infrared, Ultrasonic	Every 3 Years Urban, 6 Years Rural
	Maintenance	Surface Refinishing	Result from Visual Insp.
Underground Cables	Inspection	Visual, Infrared	Every 3 Years Urban, 6 Years Rural
Kiosk Enclosures	Inspection	Visual	Every 3 Years
Manholes / Vaults	Inspection	Visual	Every 3 Years

The following O&M programs are completed to extend the life of distribution assets, obtain a condition assessment, and improve the safety and reliability of the distribution system.

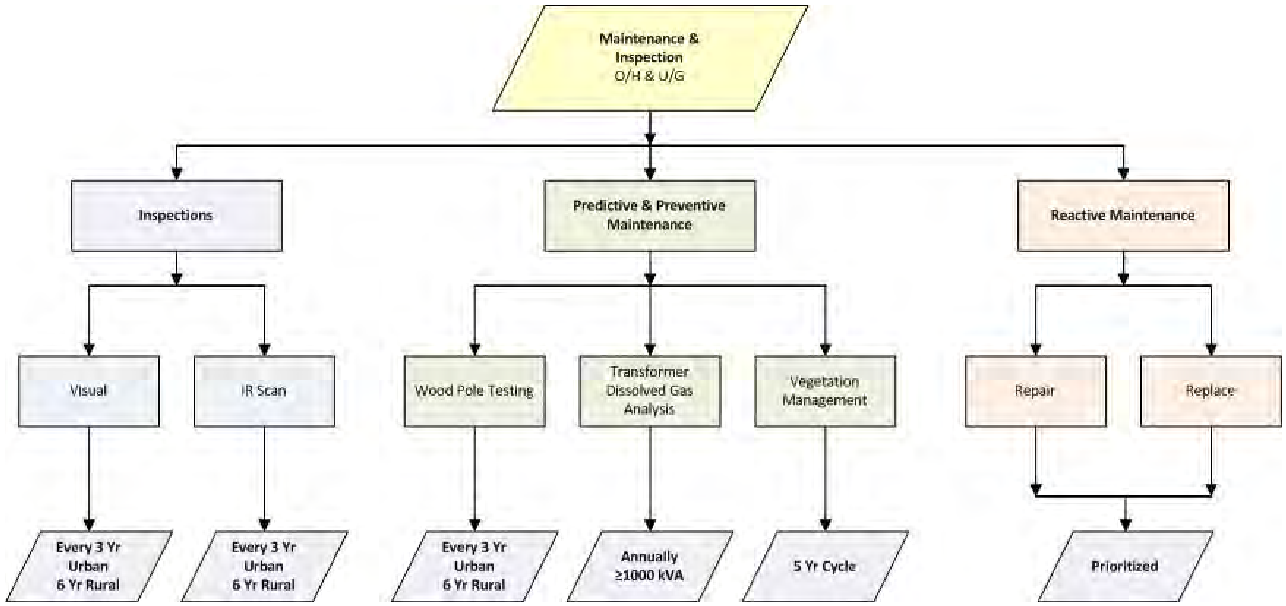


Figure 5- 35: Maintenance and Inspection Overview

Visual Inspection

The purpose of visual inspections is to identify potential safety and reliability problems and to plan mitigation actions to reduce the safety risk to the public and the risk of asset failure. Furthermore, the visual inspections are used to capture condition attributes of equipment to support NPEI's on-going renewal efforts as input data to the asset condition assessment.

NPEI currently inspects approximately one-third of its urban and one-sixth of its rural distribution system each year, as per the DSC. The visual inspections assess the condition of overhead and underground assets, including poles, distribution transformers, overhead switches, underground switchgears, overhead conductors, civil structures, insulators and additional hardware and accessories like pole attachments, sensors and surrounding vegetation.

The visual inspection maintenance program is driven by OEB compliance requirements, ESA compliance requirements, utility best practices and the need to mitigate equipment failures reducing the risk to public safety, employee safety and maintaining reliability. Though not defined in official regulatory requirements, utility best practices provide a benchmark for NPEI to adhere to.

Visual inspections allow NPEI to extract valuable information about the state of its system's repair. The condition-based assessment allows NPEI to monitor and identify defects concerning the integrity of the asset or identify issues concerning the condition of the asset. Deficiencies related to the asset are noted in the GIS database and work tickets are issued for repairs where needed.

NPEI service territory is divided into zones for inspection purposes, identified in the maps below. Each zone is identified by the year in which it is to be inspected.

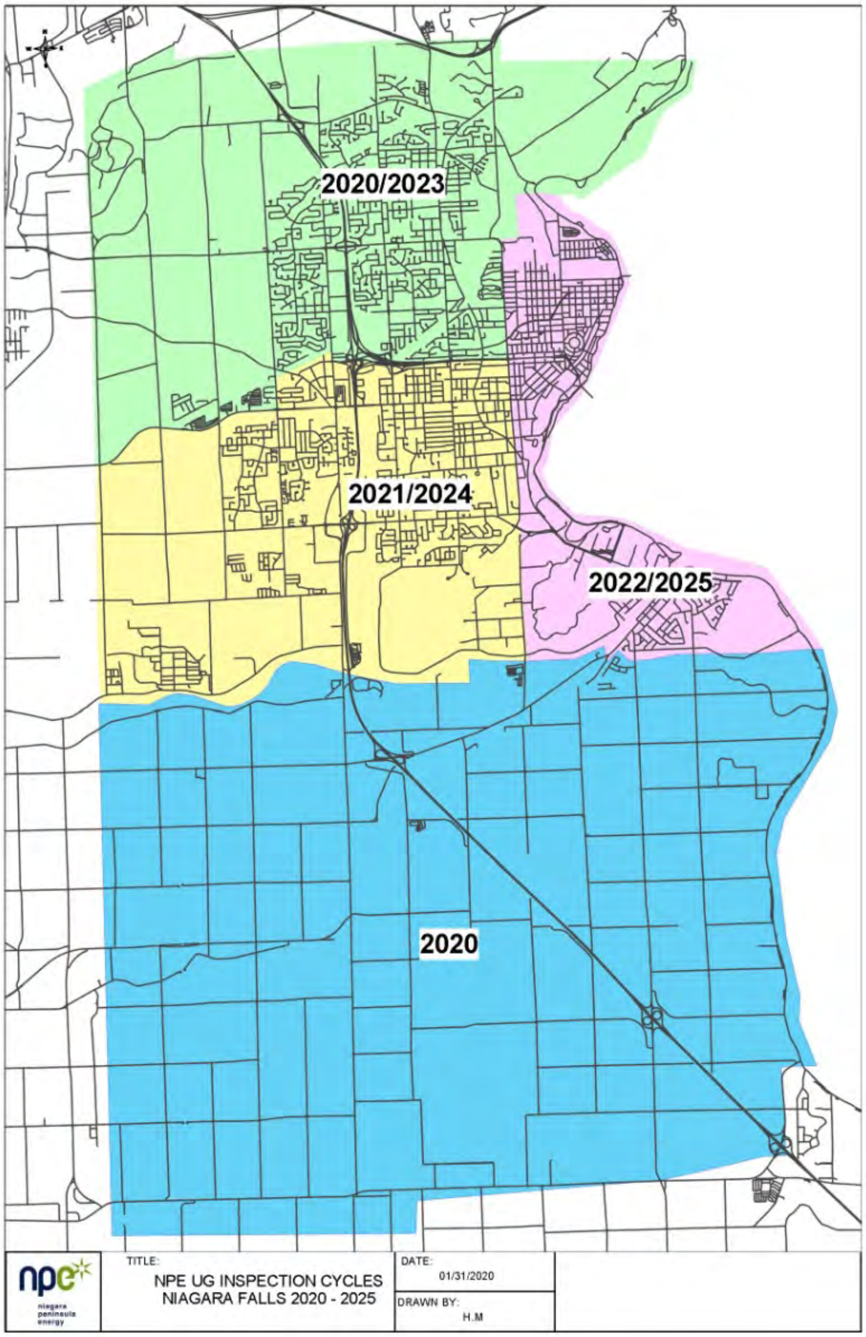


Figure 5- 36: NPEI UG Inspection Cycles – Niagara Falls

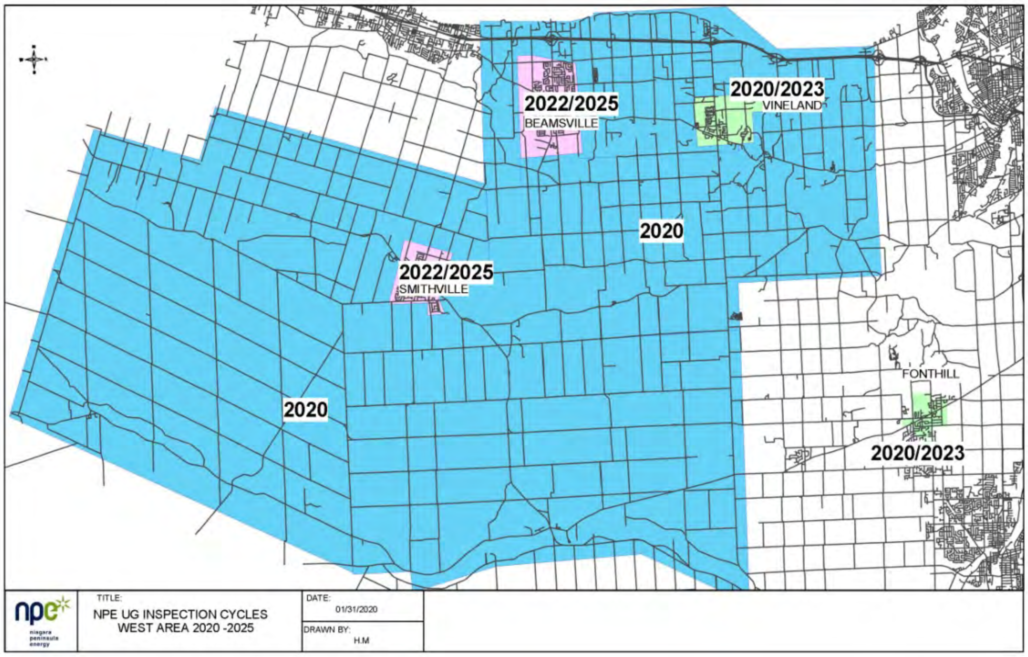


Figure 5- 37: NPEI UG Inspection Cycles – West Area

IR Scanning

Infrared thermography is a predictive maintenance action that checks for temperature variances or anomalies caused by excessive heat. The excessive heat may be attributed to connections in poor condition, overloading, or defective equipment. Infrared thermography of overhead plant is completed as needed in known problem areas, specifically where outages most commonly occur, by NPEI. Infrared thermography for the underground distribution system is completed annually on one third of the pad mounted switchgear and transformers.

During these activities, all equipment installed in the same location is checked for hot spots and general deficiencies of the facilities, including primary conductors, primary terminations, transformers, secondary cable, et cetera. These hot spots are recorded, and a summary report is produced, documenting any defect locations and severity of the defects. Maintenance to address defects, as noted in the report, is subsequently scheduled based on defect severity.

Wood Pole Testing

Wood pole testing is a predictive maintenance action that checks the integrity of the wood pole prior to experiencing a failure and avoiding the consequences of the failure. A non-destructive inspection and testing technique is used by a third-party to test the wood poles. Results from the wood pole testing are used to prioritize and support immediate and short-term remediation efforts to address the pole at risk of failure. NPEI utilizes the services of qualified power-line contractors to perform wood pole inspection and testing which also permits basic rehabilitation of installations. The pole inspection process also includes replacement of conductor guards, guy guards, and grounding repair to maintain safe operation of the asset. During the pole testing process, pole treatment is applied to extend the life of the asset.

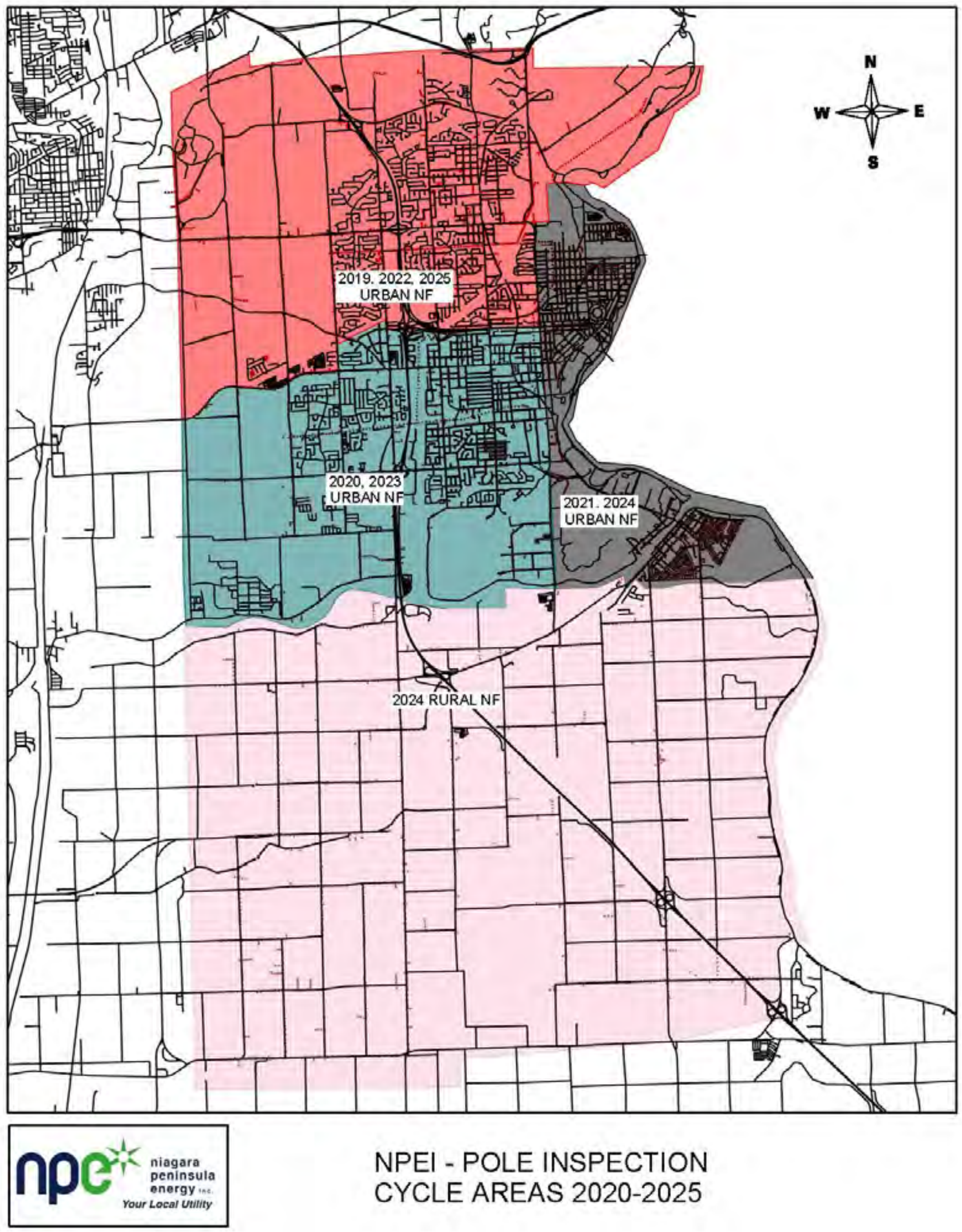


Figure 5- 38: NPEI Pole Inspection Cycles – Niagara Falls

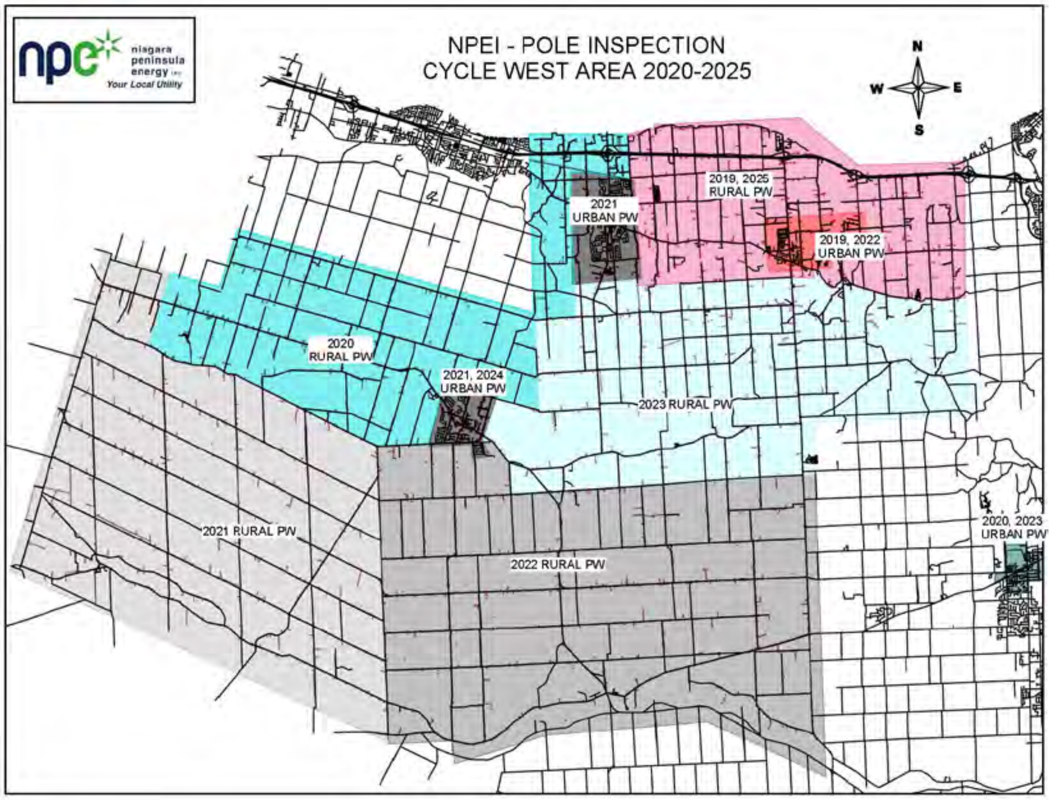


Figure 5- 39: NPEI Pole Inspection Cycles – West Area

Transformer Oil Dissolved Gas Analysis

Transformer oil analysis is a predictive maintenance test that can be used to identify potential issues and failures within oil insulated electrical equipment. The oil analysis test results indicate the relative health and predicted life of the transformer. NPEI utilizes a third party to perform transformer oil analysis on all NPEI owned distribution and power transformers equal to or larger than 1000kVA in size on an annual basis. The results are reviewed by the engineering department and maintained in a database for trending purposes and for incorporation into the asset condition assessment (ACA) process.

Vegetation Management

Vegetation management, or tree trimming, is a preventative maintenance program scheduled on a 5-year cycle. The objective is to maintain operating clearances between tree limbs and the overhead equipment as per regulation. Additionally, vegetation management identifies and removes hazardous trees at risk of falling and overhangs that can be energized. Vegetation management is required to reduce the amount of tree contact outages but additionally animal contact and wind and ice-related disturbances. The practice of routine tree trimming contributes to safety and improves system reliability.

Vegetation management is executed by third party utility arborists. Using their specialized knowledge of growth rates of various vegetation, arborists may trim back more growth in specific areas to account for the different growth rates.

NPEI takes additional preventative maintenance initiatives in their vegetation management program including tree-trimming during the implementation of capital build/rebuild projects as well as weed control around transformer stations, rural distribution stations and transformer enclosures. Additionally, a substantial amount of reactive maintenance is performed in response to requests from the public to trim or remove trees in proximity to power lines.

NPEI service territory is divided into nine zones for vegetation management, identified in the maps below. Each zone is identified by the year in which it is to be trimmed. Regular inspections of the tree trimming operations occur throughout the year to identify any quality issues, which are then resolved.

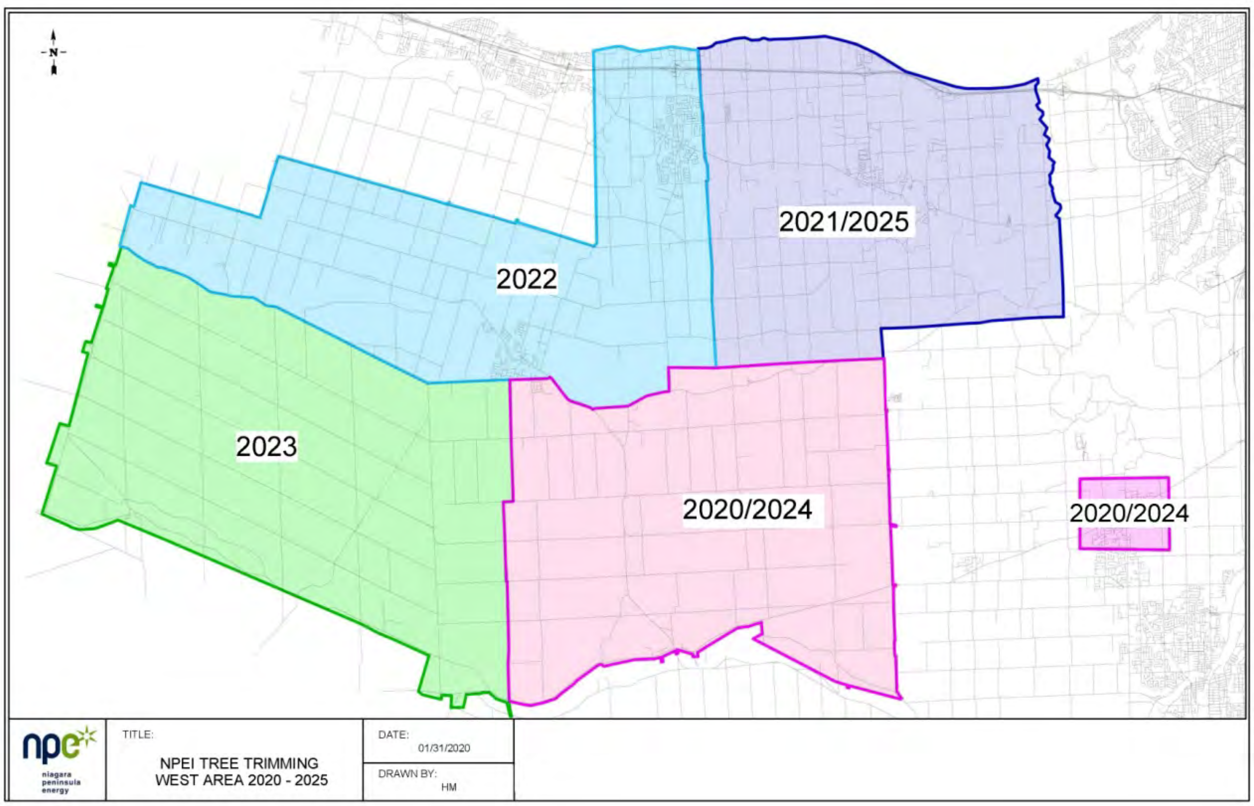


Figure 5- 40: NPEI Tree Trimming Zones – West Area

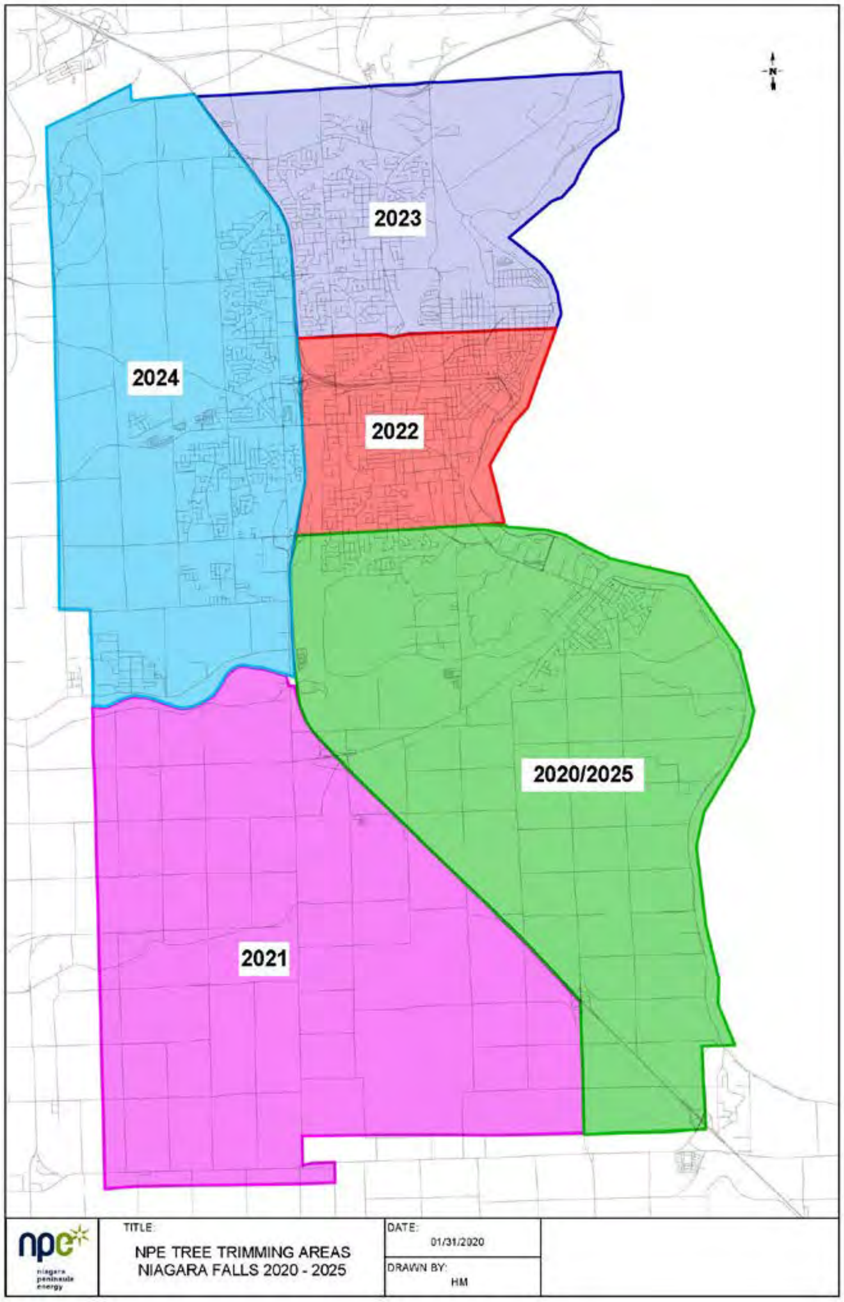


Figure 5- 41: NPEI Tree Trimming Zones – City of Niagara Falls Area

Repairs

Many of the inspection programs also include basic maintenance components such as the pole inspection program. During the pole testing process, pole treatment is applied to extend the life of the asset. NPEI utilizes the services of qualified power-line contractors to perform apparatus inspection which also permits basic repairs such as replacement of conductor guards, guy guards, and grounding repair to maintain safe operation of the asset.

Likewise, any deficiencies noted from other inspections or testing are reviewed and necessary repairs scheduled.

5.3.3.3 Maintenance and Inspection Practices Overview

Risk management is a fundamental activity in any business and in the electrical distribution industry it requires a systematic approach to assess the following attributes of each asset:

- Asset condition assessment
- Age and life expectancy
- Location
- Operational and maintenance data
- Reactive maintenance
- Preventative maintenance
- Asset replacement based on condition/age to minimize failures

It is the systematic approach of inspections, condition and age assessment, data analysis and maintenance that allow NPEI to identify and mitigate risk to its assets and distribution system. NPEI's asset lifecycle risk management philosophy is based on the need to minimize risks, extend asset useful life, optimize maintenance costs and utilize proven management processes. By conducting detailed inspections and testing where applicable, the risk associated with each asset can be identified and the pacing and prioritization of investments optimized to spread OM&A and capital costs evenly over a long period of time.

Asset performance during an investment cycle is collected and utilized in the next investment planning period. Mandatory investments are automatically included in the investment plan regardless of risk. Additional asset investments are valued and scored using NPEI's project prioritization tool and methodology. The scoring process considers each project's contribution to; System Efficiency, Customer Value, Reliability, Safety, Cyber Security, Operability, Environmental benefits and Conservation / Demand Management.

The 2021 – 2025 DSP focuses on several proactive and reactive distribution asset replacement investments. NPEI's inspection, testing and maintenance programs, described earlier, support the need for these programs. The investment strategy is designed to smooth out the impact of these programs on rates. Programs are structured to remain within OEB rate mitigation guidelines and to take into consideration the preferences of our customers. There is an increased amount of risk for those high value assets in Very Poor and Poor condition that await replacement towards the later years of the replacement program. In this sense, risk is balanced against the reality of unsustainable rate increases that would be needed to eliminate all asset risk in a short period of time. Other assets in better condition are deferred to future investment periods. Individual asset priority position in the programs will be managed as more asset information is obtained through ongoing annual inspection, testing and maintenance to optimize replacement risk decisions. Remaining assets in Very Poor and Poor condition will be dealt with on a reactive basis through programs such as pole replacements. Program funds in these categories reflect the historical cost and effort to replace these failed assets reactively.

5.3.3.4 Fleet Asset Management Strategy

NPEI's fleet assets play a critical role in keeping the organization working efficiently and safely. These assets are required to be reliable and maintained. Fleet assets consist of 105 vehicles, trailers and specialty-power operated equipment. The vehicle and equipment inventories, as of the end of 2019, are presented in the table below:

Table 5- 29: Fleet Summary

Vehicle/Equipment Type	# in Fleet
Bucket Truck	16
RBD	9
Light Truck (PickUp)	27
Car/Compact SUV	3
Van (Cargo)	6
SwapLoader	2
Flat Deck Crane Truck	1
Skid Steer	1
Forklift	3
Mobile Crane	1
Tension Stringers	2
Generator	2
Air Compressor	1
Trailers	30
Portable Substation	1

The same principles used to manage the distribution network are also used in the management of NPEI's Fleet assets. That is:

- plan appropriate resources to meet the needs of the corporation and its customers;
- replace or refurbish aging assets; and
- reduce or eliminate the length and severity of outages by having well maintained fleet assets.

Fleet asset lifecycle follows the same approach used with distribution assets which is:

- Plan
- Acquire
- Operate
- Maintain
- Dispose

NPEI maintains the Vehicle and Equipment Fleet with a combination of internal staff (three Mechanics) and external contractors. NPEI has found that operating the Vehicle Maintenance department in this way allows us to maintain the fleet, provide emergency service and specialized repairs or maintenance as required, and control costs.

In general, large vehicles (Bucket Trucks, RBDs, Service Trucks, etc.) and smaller work vehicles (pick-up trucks, vans, cars, etc.) are budgeted on a 10 to 15 year replacement schedule. Trailers and other power operated equipment are kept for longer periods of time and are scheduled for replacement when annual maintenance and repair costs escalate.

A 5-year Vehicle and Equipment replacement schedule is completed/reviewed on annual basis for large vehicles and equipment. Smaller vehicles and equipment replacements are determined on a year to year basis. When finalizing budgets/replacements for a particular year, an overall assessment of the vehicle's mileage, engine hours, age, repair history, vehicle condition and future intended use is considered. This assessment may result in the vehicle replacement being deferred to the next budget year when the vehicle would be assessed again. The table below lists the Vehicles and Equipment scheduled for replacement during the forecast period.

Table 5- 30 : Five Year Fleet Replacement Plan

Replacement Year	Size	Vehicle #	Purchase Year	Year Should be	Variance	Condition Rating	Area	Type	Description	Replacement Cost	Total
2020	Small	48	2007	2015	5	3	NF	VAN	GMC SAVANA PRO	40,000.00	40,000.00
2021	Large	42	2003	2018	3	3.6	NF	BUCKET TRUCK	FREIGHTLINER M2	420,000.00	
2021	Small	49	2007	2015	6	4	NF	VAN	CHEVROLET UPLANDER	40,000.00	
2021	Small	39	2013	2021	0	5.75	SV	LIGHT TRUCK	FORD F150 XLT	40,000.00	500,000.00
2022	Large	16	2005	2020	2	6.6	SV	RBD	INTERNATIONAL 7400	420,000.00	
2022	Small	37	2013	2021	1	4.75	SV	LIGHT TRUCK	FORD F150 XLT	40,000.00	
2022	Small	38	2013	2021	1	7.25	NF	LIGHT TRUCK	FORD F150 XLT	40,000.00	500,000.00
2023	Large	50	2008	2023	0	5	NF	BUCKET TRUCK	FREIGHTLINER M2	420,000.00	
2023	Small	17	2015	2023	0	6	NF	LIGHT TRUCK	FORD F150	40,000.00	
2023	Small	51	2009	2017	6	4	NF	VAN	CHEVROLET UPLANDER	40,000.00	500,000.00
2024	Large	58	2009	2024	0	6.8	NF	BUCKET TRUCK	FREIGHTLINER	420,000.00	
2024	Small	18	2015	2023	1	7	NF	LIGHT TRUCK	FORD F150	40,000.00	
2024	Small	19	2015	2023	1	6.75	NF	LIGHT TRUCK	FORD F150	40,000.00	
2024	Small	3	2013	2021	3	4.75	NF	LIGHT TRUCK	FORD F150 XLT	40,000.00	540,000.00
2025	Large	60	2010	2025	0	6.4	NF	RBD	FREIGHTLINER	420,000.00	
2025	Small	23	2013	2021	4	6	NF	LIGHT TRUCK	FORD F150	40,000.00	
2025	Small	35	2016	2024	1	7.75	SV	LIGHT TRUCK	CHEVROLET COLORADO	40,000.00	
2025	Small	31	2015	2023	2	7.5	SV	LIGHT TRUCK	FORD F150	40,000.00	540,000.00
											2,620,000.00

5.3.3.5 Information Technology Asset Management Strategy

NPEI's information technology (IT) assets play a critical role in keeping the organization connected and working efficiently. These assets are required to be reliable and current. IT assets include all elements of computer software and hardware that are found in the business environment at NPEI that supports both information technology (IT) and operation technology (OT). IT is used throughout this document and includes OT unless stated otherwise.

The same principles used to manage the distribution network are also used in the management of NPEI's Information Technology assets. That is:

- plan information system expansions to meet the needs of the corporation and its customers;

- replace or refurbish aging hardware and software; and
- reduce or eliminate the length and severity of information system outages.

IT asset lifecycle follows the same approach used with distribution assets which is:

- Plan & Design
- Acquire/Build
- Operate
- Maintain
- Dispose

5.3.4 System Capability assessment for renewable energy generation

NPEI has developed a Renewable Energy Generation (REG) Investment Plan to outline NPEI's ability to connect Distributed Generation (DG) systems to its distribution system as well as determine any investments required to accommodate these connections over the next five years. This plan is attached as Appendix D.

NPEI currently has 459 MicroFIT, 23 FIT, 2 load displacement, 33 net metering and 1 CHP systems connected to the distribution system, representing a total of 21.5MW of potential generation. The amount of new generation connections is expected to decrease in the short term due to the cancellation of the MicroFIT and FIT programs. NPEI anticipates that customers will shift their focus to NET metering, and alternate DER projects, but adoption may be guarded temporarily as the electrical energy market is going through a period of transformation.

NPEI's distribution system is constantly monitored to ensure the ability to connect renewable energy generation to the grid. NPEI does not currently see a need for immediate investment to accommodate generator connections, but is prepared to add items to our long term budget if there are unforeseen changes on specific feeders, causing investment to be required.

5.3.4.1 Present Levels of Distributed Generation Connections

NPEI has connected more than 500 generators, totalling over 21MW of potential generation to the distribution system which is summarized in the table below:

Table 5- 31: Summary of Existing Connected Generation

Station	Bus Name	Feeders	NUG		FIT		MicroFit		Net Metering		CHP		LD		Total	
			Count	kW	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW
Murray	QZ	M51, M52, M53, M54, M55, M56	0	0	0	0	37	358	2	13	0	0	0	0	39	371
Murray	Y1Y2	M25, M26, M27, M28, M29, M30	0	0	0	0	8	76	1	4	0	0	0	0	9	80
Murray	J	M10, M11, M13	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Murray	K	M14, M15, M16, M17, M18	0	0	1	75	7	70	1	5	0	0	0	0	9	150
Kalar	BY	KM1, KM2, KM3, KM4, KM5, KM6, KM7, KM8	0	0	1	1000	71	682	2	25	0	0	0	0	74	1707
Stanley	BY	M1, M2, M3, M4, M5, M6	0	0	3	370	10	94	0	0	0	0	1	35	14	499
Stanley	QJ	M31, M32, M33, M41, M42, M43	0	0	0	0	36	352	1	10	0	0	0	0	37	362
Beamsville	BY	M1, M2, M3, M4	0	0	9	1940	122	1183	9	172	0	0	0	0	140	3295
NWTS	BY	M2, M3, M4, M5	0	0	5	9790	56	539	14	183	1	2731	0	0	76	13243
Vineland	T1	F1	0	0	2	500	69	651	2	11	0	0	1	160	74	1322
Vineland	T2	F2	1	300	2	75	34	335	0	0	0	0	0	0	36	410
Allanburg	BY	M6, M7, M8	0	0	0	0	9	89	1	5	0	0	0	0	10	94
Total			**1**	**300**	**23**	**13750**	**459**	**4429**	**33**	**428**	**1**	**2731**	**2**	**195**	**518**	**21533**

5.3.4.2 Capacity for the Connection of Distributed Generation

NPEI has done an assessment to determine the amount of generation that can be connected to the distribution system. It is imperative that the addition of new generation does not damage distribution equipment or create safety concerns due to short circuit conditions. Equipment must also be rated to meet the thermal capacity requirements of the system at all times, so as to minimize line losses and to reduce the risk of premature failure of equipment. All generation that is connected to NPEI's system must be equipped with anti-islanding and protections schemes, which ensures that generators do not create islanding situations, which may cause damage to equipment during outages. Large generators operating in parallel with the distribution system are required to install transfer-trip as per Hydro One's TIR.

The following table summarizes the available capacity at all of the transformer stations in NPEI's distribution territory as well as the connected generation.

Table 5- 32: Summary of Available DG Capacity at Transformer Stations

Station	Bus Name	Feeders	Voltage (kV)	SC Cap. (MVA)	Thermal Cap. (kW)	Existing DG Non-Renew	Existing DG Renewable	Remaining Capacity
Murray	QZ	M51, M52, M53, M54, M55, M56	13.8	84.7	1200	0.0	371	829.0
Murray	Y1Y2	M25, M26, M27, M28, M29, M30	13.8	88.9	1240	0.0	80	1160.0
Murray	J	M10, M11, M13	13.8	119.3	1400	0.0	0	1400.0
Murray	K	M14, M15, M16, M17, M18	13.8	119.3	9400	0.0	150	9250.0
Kalar	BY	KM1, KM2, KM3, KM4, KM5, KM6, KM7, KM8	13.8	17.6	11000	0.0	1707	9293.0
Stanley	BY	M1, M2, M3, M4, M5, M6	13.8	68.3	7100	35.0	464	6636.0
Stanley	QJ	M31, M32, M33, M41, M42, M43	13.8	15.2	10300	0.0	362	9938.0
Beamsville	BY	M1, M2, M3, M4	27.6	372.9	32400	0.0	3295	29105.0
NWTS	BY	M2, M3, M4, M5	27.6	113.7	15000	2731.0	10512	4488.0
Vineland	T1	F1	27.6	431.3	14500	160.0	1162	13338.0
Vineland	T2	F2	27.6	430.4	14500	300.0	110	14390.0
Allanburg	BY	M6, M7, M8	27.6	59.6	24800	0.0	94	24706.0
Total					**142840.0**	**3226.0**	**18307**	**124533.0**

5.3.4.3 Projected Renewable Generation Growth

With the elimination of the FIT and MicroFIT programs, NPEI has already seen a decrease in the number of distributed generation projects. Projects have shifted to net metering, load displacement and CHP/cogen projects. Based on connection and application activity over the months since the MicroFIT program has ended, NPEI anticipates a small decrease in distributed generation connections in 2019 and 2020. We have seen an increase in enquiries relating to energy storage and load displacement projects, though preliminary proposed project timelines would indicate the connections would be scattered over the next few years. NPEI's forecast for 2019 to 2025 can be seen in the Table below.

Table 5- 33: Summary of Available DG Capacity at Transformer Stations

Year	FIT		MicroFit		Net Metering		CHP		LD		Total	
	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW
2019	0	0.0	0	0.0	15	304.2	0	0.0	1	1000.0	16	1304.2
2020	0	0.0	0	0.0	15	299.0	0	0.0	1	995.0	16	1294.0
2021	0	0.0	0	0.0	16	308.0	0	0.0	2	2000.0	18	2308.0
2022	0	0.0	0	0.0	16	308.0	0	0.0	0	0.0	16	308.0
2023	0	0.0	0	0.0	17	317.0	0	0.0	1	1000.0	18	1317.0
2024	0	0.0	0	0.0	17	317.0	0	0.0	0	0.0	17	317.0
2025	0	0.0	0	0.0	18	326.0	0	0.0	1	1000.0	19	1326.0
Total	**0**	**0.0**	**0**	**0.0**	**114**	**2179.2**	**0**	**0.0**	**6**	**5995.0**	**120**	**8174.2**

Notes

1 Net meter count and kW for 2019 are based on actual connected and projected for the remainder of the year.

2 Net metering count beyond 2019 is based on 3% growth per year.

3 Net metering kW calculation beyond 2019 is done as follows:

(4 > 10kW projects at an average of 50kW) + (Remainder of projects < 10 kW at an average of 9 kW)

4 Load displacement projects for 2019 = 1MW, 2020 = 995Kw, 2021 = 1MW x 2

5 Load displacement projects beyond 2021 are an estimation of 1 project @ 1MW every other year

5.3.4.4 Investments to Facilitate Renewable Energy Generation

NPEI is committed to investments related to connecting renewable energy generation if it is required. NPEI has reviewed the need for capital and OM&A expenditures for the purpose of expanding the distribution system to enable future REG connections. Based on historical trends and anticipated future REG connections, no expenditure is anticipated between 2019 and 2025 that will be required for constructing feeder assets to specifically accommodate renewable energy connections.

NPEI will be continuously monitoring whether additional investments need to take place so REG can be connected to the system.

5.4 CAPITAL EXPENDITURE PLAN

This section describes NPEI’s five-year capital expenditure plan over the forecast period, including a summary of the plan, an overview of NPEI’s capital expenditure planning process, an assessment of NPEI’s system to connect new REG, a summary of capital expenditures, and justification of capital expenditures.

NPEI’s DSP details the program of system investment decisions developed based on information derived from NPEI’s asset management and capital expenditure planning process. Investments, whether identified by category or by specific project, are justified in whole or in part by reference to specific aspects of NPEI’s asset management and capital expenditure planning process.

NPEI’s DSP includes information on prospective investments over a five-year forward-looking period (2021 – 2025) as well as planned and actual information on investments over the historical period (2015 – 2019).

5.4.0 Capital Expenditure Plan Considerations

NPEI's Capital Expenditure Plan is divided into four investment categories as identified in the Chapter 5 filing requirements: System Access, System Renewal, System Service, and General Plant. The asset management process takes the following drivers into account:

5.4.0.1 Customer Engagement and Preferences

5.4.0.1.1 Customer Engagement

Customer engagement is considered essential to achieving NPEI’s Customer Focus outcomes. NPEI believes that customer engagement with respect to DSP outcomes should provide useful information, be cost-effective, and be able to engage as many customers as reasonably possible. The goal is to capture preferences with respect to the underlying principle of the DSP to maintain existing service levels over the period of the plan. NPEI undertakes several ongoing customer engagement activities daily, including:

1. Direct Engagement
    - Telephone calls, emails, written notices, in-person interactions at offices
    - Community meetings
    - Information displays
    - Employee volunteerism and corporate donations
    - Electrical Safety Program for the public
    - Bill inserts and rate brochures
    - Media releases and alerts
2. Online Engagement
    - Corporate website
    - My Account online bill portal for residential and commercial customers
    - Online outage map

- Social Media (Twitter, Instagram, LinkedIn, YouTube)

3. Customer Survey Program
    - Customer Satisfaction Surveys
    - Public Safety Awareness Surveys
    - Customer Feedback surveys (recently completed in 2016 and 2018)

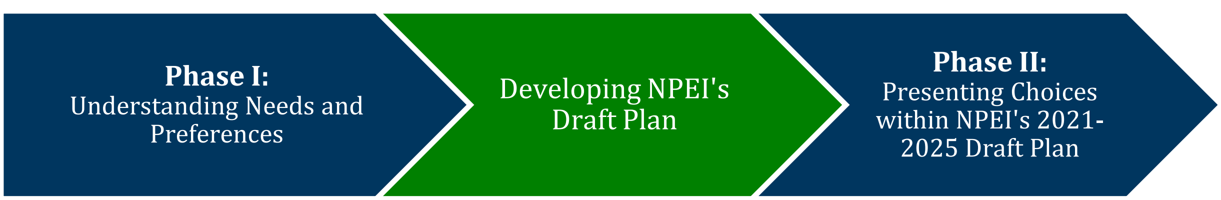
5.4.0.1.2 Customer Preferences

In May 2019, Innovative Research Group Inc. (INNOVATIVE) was engaged by Niagara Peninsula Energy to assist in meeting the utility's customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors (RRFE).

Between June and December 2019, Niagara Peninsula Energy gathered feedback from more than 3,000 residential, small business and commercial customers through its customer engagement efforts - in context, Niagara Peninsula Energy, through INNOVATIVE, engaged with nearly 6% of its entire customer base.

Throughout this customer engagement, a concerted effort was made to ensure that all customers – regardless of where they live or operate, or how much electricity they use - had an equal opportunity to participate, whether through voluntary or random sampling. In order to facilitate the collection of this robust feedback, INNOVATIVE and NPEI developed a two-phased approach which was both iterative and responsive at each stage of feedback.

Undertaking a two-phased approach also enabled NPEI a clear opportunity to demonstrate how customer feedback collected in Phase I was incorporated into the utility's draft plans, and will enable them to clearly respond to actionable feedback gathered in Phase II. Incorporating customer feedback into NPEI's plans was a key objective of this customer engagement, and this two-phased approach helped facilitate its achievement.



This document contains the results of both phases of customer engagement, with a focus on the generalizable results of the representative sample from Phase II.

5.4.0.1.3 Customer Engagement Key Findings

Phase I: Understanding Needs and Preferences

The first phase of NPEI's 2019 customer engagement look place between **June and July 2019** with a series of focus groups, and telephone and online surveys.

The purpose of this initial phase of engagement was to provide NPEI planners with input on customers' needs and preferences as they relate to the outcomes and goals that the utility should focus on over the 2021-2025 period; as well as develop a detailed understanding of the differences between customers with known email addresses (email sample) and the broader customer base (telephone sample).

This initial phase of engagement was conducted at the beginning of NPEI's planning cycle in order to ensure that the draft plan distinctly took into consideration the views of customers.

In June 2019, an initial round of four exploratory focus groups were conducted amongst residential and small business customers in both Niagara Falls and West Lincoln. One primary objective of these groups was to obtain insights into what customers expect of NPEI, what are their priorities, both in context of valued outcomes, and the investment choices impacting customers that the utility will need to make.

NPEI's customer engagement was an iterative process, wherein each phase and activity informed the next. The results of these exploratory focus groups played an important role in informing the questions that were asked in a subsequent series of telephone and online surveys.

In addition to OEB direction on LDC rate application filings contained in the RRFE, its Handbook for Utility Rate Applications notes the following: *"The OEB expects a utility's rate application to provide an overview of customer needs, preferences and expectations learned through the utility's customer engagement activities*."[1] This section provides an overview of customer needs, preferences and expectations as gathered through parallel online and telephone surveys.

Customer Needs

Needs questions focus on understanding the gap between the services and experience customers want and the services and experience customers are receiving.

In the initial exploratory focus groups, participants noted that they were satisfied with the services they receive from NPEI, including both customer service and, the level of reliability they experience.

Overall Satisfaction with Niagara Peninsula Energy

The Phase I surveys confirmed that most residential and small business customers are satisfied with the level of service that NPEI provides.

[1] Handbook for Utility Rate Applications, p. 12 (October 13, 2016)

Phase I Telephone Reference Survey	Residential	Small Business
Satisfied	89%	87%
Dissatisfied	6%	3%

What can NPEI do to improve services?

Looking beyond top line customer satisfaction, to uncover whether there is a gap between the services and experience customers want and what they are receiving, we asked what NPEI could do, if anything, to improve services.

In the exploratory focus groups, many customers felt that the price of electricity was the central area where NPEI could improve service. That said, very few had an initial understanding of NPEI's role in the electricity system, including the portion of their bill that is remitted to the utility. Additionally, some customers felt that there was a lack of customer education regarding the system as a whole, with particular emphasis on helping customers reduce their electricity bills.

In the Phase I telephone survey, the majority of residential and small business customers noted that they either didn't know how services could improved or expressed that there was nothing in particular that the utility could do to improve service. Similar to the focus groups, about 1-in-5 customers noted that the NPEI could improve services by reducing rates.

Phase I Telephone Reference Survey	Residential	Small Business
1st	*Don't know* (30%)	*Don't know* (35%)
2nd	*None* (24%)	*Lower/Reduce rates* (21%)
3rd	*Lower/Reduce rates* (22%)	*None* (15%)

The combination of high levels of satisfaction, as well as a majority of customers not indicating how NPEI can improve services, leads to conclusion that the utility is meeting current customer needs.

Customer Preferences

Preference questions focus on customer views on the outcomes the utility should focus on, priorities among those outcomes, and trade-offs as illustrated by choices on specific programs or the pacing and prioritization of investments.

One of the objectives of the exploratory focus groups was to develop a list of outcomes/goals that NPEI should focus on in its upcoming rate application. Upon building this list with qualitative customer feedback, the Phase I surveys focused on confirming whether this list was exhaustive, in addition to quantifying customer preferences to the broader customer base.

This list featured seven outcomes /goals:

- *Ensuring reliable electrical service*
- *Delivering electricity at reasonable distribution rates*
- *Providing quality customer service and enhanced communications*
- *Proactively replacing aging infrastructure that is beyond its useful life*
- *Finding internal efficiencies and ways to find cost savings*
- *Upgrading the electrical system to better respond to and withstand the impact of adverse weather and climate change*
- *Providing tools and services that allow customers to better manage their electricity usage*

Based on the generalizable feedback from the Phase I telephone surveys, customers don't expect NPEI to just focus on one outcome. In fact, the majority of both residential and small business customers feel that almost all of the identified outcomes are *extremely important* (with the exception of providing tools to better manage electricity).

What outcomes do customers prioritize?

Among competing outcomes, *price*, *reliability*, and *finding internal cost efficiencies* are the top three priorities for both residential and small business customers. When ranked relative to other priorities, NPEI customers see price as the top outcome that the utility should focus on.

Telephone Survey	Phase I Telephone Reference Survey	
	Residential	Small Business
Top Priority	*Delivering electricity at reasonable distribution rates*	*Delivering electricity at reasonable distribution rates*
2nd Priority	*Ensuring reliable electrical service*	*Ensuring reliable electrical service*
3rd Priority	*Finding internal efficiencies and ways to find cost savings*	*Finding internal efficiencies and ways to find cost savings*

What reliability outcomes do customers prioritize?

Beyond the priority of ensuring reliability electrical service, customers were asked which aspect of the reliability outcome NPEI should focus on. *Reducing the overall number of outages*, the *overall length of outages*, and *improving restoration times* are the top three priorities for both rate classes.

Telephone Survey	Phase I Telephone Reference Survey	
	Residential	Small Business
Top Priority	*Reducing the overall number of outages*	*Reducing the overall number of outages*
2nd Priority	*Reducing the overall length of outages*	*Reducing the overall length of outages*
3rd Priority	*Reducing the length of time to restore power during extreme weather events*	*Reducing the length of time to restore power during extreme weather events*

What investment trade-offs do customers value most?

Beyond developing an understanding of the needs and outcomes that customers prioritize, the Phase I surveys also explored general trade-offs between several types of investments and cost.

These questions were intended to provide preliminary input for NPEI in putting together their initial draft plan.

In fact, the results from these surveys were summarized, providing a high-level summary of the findings from the Phase I surveys, including both needs and preferences. This was shared with NPEI planners and helped ensure that customer feedback was brought into the planning process in the early stages.

Replacing Aging Infrastructure (System Renewal)

While keeping prices at a reasonable and affordable level is an important priority for customers, the majority feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Phase I Telephone Reference Survey	Residential	Small Business
Invest what it takes to maintain reliability	62%	64%
Defer investments to lessen bill impacts	26%	19%

Proactive Investments in Grid Modernization (New Technology)

The majority of residential and small business customers are willing to consider paying more to invest in maintaining reliability, equipping staff with equipment and IT systems. Knowing that it could eventually save money, they supported proactively investing in system capacity, and modernizing the grid.

Further, the majority of customers support proactive investment in both system capacity and grid modernization. Relative to other trade-offs, support for investment in system capacity is least intense.

Phase I Telephone Reference Survey	Residential	Small Business
Make proactive investments	62%	55%
Make investment prioritizing lowest cost	25%	21%

Using the input from the Phase I customer engagement, NPEI planners developed a draft plan that included an estimated baseline cost and identified a number of investment areas where pacing could be accelerated, or slowed down, in order to align with customer needs and expectations.

The Phase II customer engagement focused on presenting these investment trade-offs to customers and gathering feedback on NPEI's draft plan. The next section will summarize the findings from these activities.

Phase II: Introduction

The second phase of NPEI's customer engagement focused on customer preferences on pacing and balancing outcomes. In order to obtain this feedback, an online "workbook" was deployed to all customers with an email address on file, as well as promoted through a generic link on NPEI's website and social media platforms.

This workbook was designed to both educate customers on NPEI's role in the electricity system and its draft business plans, as well as to gather feedback on trade-offs between seven specific investments.

Prior to developing this customer engagement workbook, NPEI staff used customer feedback, collected throughout the Phase I engagement, to help align its 2021 to 2025 investment plan with customer expectations.

Phase II of the engagement focused on two core objectives:

1. Confirming customers' needs, preferences and priorities identified in Phase I; and,

2. Soliciting customer feedback on the content of NPEI's draft plan, including customer preferences towards particular capital investments where trade-offs on pacing exist.

The seven specific investments were presented in the form of trade-off questions. In most cases, these investments were presented as a choice between several approaches – the pace of investment included in NPEI's draft plan; an *accelerated pace*; or a *reduced pace*. The individual bill impact (customized by rate class) of each approach was presented alongside the choice.

Beyond presenting bill impacts for individual approaches to pacing investments, the workbook allowed customers to review the cumulative impact of their choices and adjust their responses using a dynamic "bill calculator". Customers were able to change their responses until they felt they had found the right pace of investments and estimated rate impact.

The following section summarizes customer feedback from the online workbook which was sent to all residential, small business and GS >50 kW customers with an email on file.

Phase II: Key Findings

Overall, a strong majority of NPEI customers, in each rate class, support either what is currently included in the utility's draft plan, or an approach that accelerates the pace of investment.

In fact, when it comes to *underground cable replacement, overhead pole replacement*, and *overhead transformer replacement*, many customers from each rate class, support an accelerated investment approach. These three investments consistently received the strongest levels of support.

The results below demonstrate that regarding *underground cable replacement, overhead pole replacement*, and *overhead transformer replacement,* most customers support an approach that falls somewhere between what is included in the draft plan and a more accelerated pace of investment.

Underground Cable Replacement

Relative to other investment options presented to customers, underground cable replacements received some of the highest levels of support for an accelerated approach. Almost equal proportions of residential and small business customers support an accelerated approach, while GS >50 kW customers are more divided between what is currently included in the draft plan and a more proactive investment approach.

Underground Cable Replacement *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Further Accelerated Pace	29%	31%	2/32	25%
Accelerated Pace	36%	37%	14/32	36%
Included in Draft Plan	35%	32%	16/32	38%

Despite a correlation between whether your electricity bill has a significant impact on household finances and the likelihood of supporting a move accelerated approach to underground cable replacement, a majority of all respondents either support the approach in the draft plan or an accelerated pace. In fact, a majority of residential customers who say their bill has a *significant* impact on their households' finances support either the current or an accelerated approach.

Underground Cable Replacement *Residential Customers*	Bill Impact on Finances		
	Significant Impact	Impact	No Impact
Accelerated Pace	27%	24%	34%
Included in Draft Plan	31%	39%	37%
Slower Pace	43%	37%	29%

Overhead Pole Replacement

Overhead Pole Replacement *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	47%	56%	10/32	45%
Included in Draft Plan	35%	31%	15/32	33%
Slower Pace	18%	13%	7/32	22%

Overhead Transformer Replacement

Overhead Transformer Replacement *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	47%	53%	14/32	45%
Included in Draft Plan	36%	28%	12/32	33%
Slower Pace	17%	19%	6/32	23%

Grid Modernization

With regards to investments in Supervisory Control and Data Acquisition (SCADA) systems, NPEI customers are almost evenly divided. Nearly equal proportions of residential, small business and GS >50 kW customers support either the approach included in the draft plan, or an accelerated one that would see the number of devices installed doubled over the next five-year period.

Grid Modernization *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	41%	41%	12/32	33%
Included in Draft Plan	44%	41%	14/32	46%
Slower Pace	14%	18%	6/32	20%

Despite strong overall support for an accelerated approach to installing SCADA systems, there is a high degree of correlation between bill impact on finances and one's likelihood to support higher levels of spending. In fact, more "vulnerable" residential customers are more likely to support a flower pace than an accelerated pace of investment.

Grid Modernization *Residential Customers*	**Bill Impact on Finances**		
	Significant Impact	Impact	No Impact
Accelerated Pace	26%	38%	50%
Included in Draft Plan	38%	47%	44%
Slower Pace	36%	15%	6%

The investments which received the lowest levels of support relative to the other options presented included: *Converting outdated underground kiosk transformers*, *subdivision underground rehabilitation*, and *overhead rebuilds*.

Converting Outdated Underground Kiosk Transformers

Converting underground kiosk transformers was the one investment option that was presented without an accelerated approach. The pace included in the draft plan, which was in line with historic rates of replacement, was supported by the majority of customers in each rate class.

That said, nearly 4-in-10 residential and small business customers expressed their support for an investment pace below what is included in the draft plan. This propensity to support a slower investment pace was the lowest amongst the seven investment options presented to customers.

Kiosk Transformers *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Included in Draft Plan	56%	60%	21/32	45%
Reduced Pace	30%	23%	4/32	39%
Slower Pace	14%	17%	7/32	17%

When it comes to replacing kiosk transformers, customers who's bill significantly impacts their finances hold much different views than other customers. In fact, a strong majority of these customers say that NPEI should take a slower approach to replacing this equipment compared to what it currently being proposed.

Kiosk Transformers *Residential Customers*	Bill Impact on Finances		
	Significant Impact	Impact	No Impact
Included in Draft Plan	27%	53%	69%
Reduced Pace	37%	33%	25%
Slower Pace	36%	14%	6%

Relative to the other investments presented to customers, *subdivision underground rehabilitation*, and *overhead rebuilds* saw the weakest support for an accelerated investment approach. About 3-in-10 residential and small business customers supported an accelerated pace, while a plurality would prefer what is currently included in the draft plan.

Subdivision Underground Rehabilitation

In fact, a plurality (14 of 32) GS >50 kW customers supported a slower pace of subdivision underground rehabilitation, provided that they would not be directly impacted by such investments.

Subdivision Underground Rehabilitation *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	33%	34%	6/32	31%
Included in Draft Plan	45%	52%	12/32	45%
Slower Pace	22%	14%	14/32	24%

Overhead Rebuilds

Similarly, almost equal proportions of customers in all rate classes offer the same levels of support for *overhead rebuilds*.

Overhead Rebuilds *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	32%	35%	5/32	26%
Included in Draft Plan	50%	45%	19/32	52%
Slower Pace	19%	20%	8/32	23%

Cumulative Bill Impacts

After providing their preferences on the seven investments presented in the workbook, customers had the opportunity to review the cumulative impact of their choices and adjust their responses using a dynamic "bill calculator".

It was made clear to participants that these impacts were *in addition to* what is included in the draft plan, for residential customers, this was a 2.5% increase over 5-years. If customers selected the *"Included in the Draft Plan"* option for each investment, the rate impact was zero. For residential customers, the range of potential impacts was +$0.23 if they selected all of the most accelerated approaches, and -$0.10 is they consistently selected the slowest approaches.

On average, customers did not make significant changes to their initial responses. In fact, for both residential and small business customers, the average rate increase rose by $0.01 after customers had the opportunity to adjust their responses. Customers on average were more likely to select the accelerated pace of investment once given the opportunity to see the cumulative impact of their choices. It should be noted, however, that these changes cannot be deemed statistically significant, essentially meaning that there was no change from initial to final responses.

Cumulative Bill Impacts	Residential	Small Bus.
Average Initial ($)	$0.08	$0.16
Average Final ($)	$0.09	$0.17

Assessing NPEI's Draft 2021-2025 plan

Overall, customers in all rate classes are prepared to pay for the level of investment included in NPEI's draft plan. In fact, customers are between two and three times as likely to support a more accelerated investment approach compared to a slower approach that keeps rates below what it currently proposed.

Again, when it comes to *overhead pole replacement*, *overhead transformer replacement*, and *underground cable replacement,* most customers support an approach that falls somewhere between what is included in the draft plan and a more accelerated pace of investment.

Assessing NPEI's Draft Plan *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Improve service, even if it exceeds proposed increase	33%	26%	4/32	27%
Maintain proposed increase	49%	57%	20/32	45%
Keep increases below proposed	11%	13%	6/32	18%
Other	2%	1%	1/32	2%
Don't know	5%	2%	1/32	9%

Specific attention has been paid to how those whose electricity bill has a significant impact on their households' (or business') finances opinions vary from the broader customer base. Reflecting their financial capacity, those who agree that their electricity bill has a *significant impact* on their household's finances are less supportive of investments than the average customer but still generally support NPEI's draft plan and the associated impacts. Still, it is important to note that about 3-in-10 of these more "vulnerable" customers believe that NPEI should keep increases below what is currently proposed.

Assessing NPEI's Draft Plan *Residential Customers*	Bill Impact on Finances		
	Significant impact	Some Impact	No Impact
Improve service	17%	27%	43%
Maintain increase	36%	55%	50%
Keep increases below	29%	13%	3%

5.4.0.2 System Development over the Forecast Period

5.4.0.2.1 Ability to Connect New Load Customers

In the West Lincoln / Lincoln area of NPEI's service territory, there is sufficient capacity at the transformer station level to accommodate expected short-term load growth. Niagara West TS was constructed in 2004 (owned by Grimsby Power Inc.) and was constructed primarily to alleviate capacity constraints at Beamsville TS. Beamsville TS is Hydro One owned and the station power transformers were replaced with new units in 2009. Vineland DS has 2 power transformer units that supply a single feeder each and are approaching their capacity limits.

Historical and forecast capital expenditures in the West Lincoln / Lincoln area include expansion of the 27.6kV system to alleviate capacity constraints on the 8.32kV system. The 8.32kV stations have been stabilized by refurbishment. Transfer of some load to the 27.6kV system and load balancing has resulted in current peak load levels at the 8.32kV distribution stations to remain below 75% of capacity. The Campden DS power transformer was replaced as part of the 2018 Capital Program.

In the Fonthill area, NPEI introduced a redundant supply in 2009 providing ample capacity on the 27.6kV system. Both municipal stations with primary distribution at the 4.16kV level have been refurbished. Each station operates with a peak load at less than 65% of capacity. The Station Street DS power transformer was replaced as part of the 2017 Capital Program.

The Niagara Falls service area has capacity available at Murray TS on the 13.8kV system. The Kalar TS has transformer capacity available, however, the existing bus arrangement is nearing its' capacity limits. The 2021 Capital Program incorporates the installation of the planned second bus arrangement to allow for utilization of the transformer capacity to support load growth. There are significant load transfer capabilities between all three TS points which allows load transfer to manage load growth. Similar to the West Lincoln / Lincoln area, historical and forecast capital expenditures have included expansion of the 13.8kV system to alleviate load from the 4.16kV municipal stations. The municipal stations operate with a peak load at less than 75% of nameplate capacity. The forecast capital expenditures include conversion of loads to the 13.8kV system in advance of elimination of municipal substations which are at end of life and / or have access impediments.

5.4.0.2.2 Load and Customer Growth

NPEI maintains a close relationship with the Municipalities that it serves and their respective Development and Planning staff. Discussions include planned activities that can affect budgets, BIA/Municipality redevelopment plans and scheduling/coordination on a per project basis and during construction season.

The Niagara Region has been included in the "A Place to Grow" growth plan for the Greater Golden Horseshoe plan by the province of Ontario. The province has set a growth forecast of 610,000 people for the Niagara Region by 2041. This is an increase of 168,000 people between 2011 (the last Census year) and 2041. In response to this forecast, the Niagara Region has initiated their own "Niagara 2041 Growth Strategy". The projected yearly growth rates within NPEI's service territory for the forecast period of this DSP are: 1.11% for Lincoln, 1.41% for Niagara Falls, 1.55% for Fonthill (Pelham) and 2.83% for West Lincoln.

5.4.0.2.3 System Development

System Renewal investments (end of life replacement) will ensure that customer service levels with respect to reliability are maintained. Condition monitoring and performance analytics help direct preventive maintenance to specific at-risk equipment and extend further the safe reliable useful life of all equipment.

System Access investments will provide for overhead and underground plant relocation due to road widening, new connections and revenue metering to service increased development densities.

System Service innovation and reliability investments will be pursued where prudent and prioritized. Investments in system expansion to supply load growth are planned for and scheduled to come online in time for the realization of the increased demand in certain parts of the service territory such as in the area of the proposed South Niagara Hospital.

Expansion of the 27.6kV and 13.8kV main feeder distribution systems are aimed at improving reliability, stabilizing capacity, and reducing the overall distribution system loss component. Expansion of these systems also extends NPEI's back-feed capability to improve restoration times during contingencies. Grid sectionalizing devices are incorporated into expansion plans to permit optimization of feeder loading. The devices also provide additional system protection elements to reduce overall feeder exposure during contingencies.

NPEI's historical and forecast expenditures have targeted distribution substations that will remain a key component of the system beyond 2025. These stations are being stabilized with upgraded transformation, protection systems, and backup DC power systems. Where distribution systems are at end of life in conjunction with the supplying distribution station, voltage conversion projects are part of the capital expenditure plan. Voltage conversions, where cost feasible, renew assets at end of life and contribute to the elimination of station equipment such as power transformers that are approaching end of life.

5.4.0.2.4 Climate Change Adaptation

Recent years have seen more severe and more frequent storms as a result of climate change. The impacts on a power distribution system include high electrical demand and unusual operating conditions resulting from extreme temperatures and ice and wind damages to overhead lines and poles due to wind and ice storms. These abnormal activities have the potential to cause significant customer outages. To respond to these changes, NPEI is undertaking a number of initiatives to harden the distribution system and make it more resilient to extreme weather events. Initiatives include rebuilding assets identified as in poor condition in the ACA report to current day design standards, utilizing stronger materials, utilizing stainless-steel equipment when required, improving grid flexibility using automated reclosers, proactive tree trimming, and proactive inspection and maintenance. These activities will continue and be enhanced in some areas over the period of the DSP.

5.4.0.2.5 Grid Modernization Strategy

A portion of NPEI's forecast capital expenditures are focused on grid modernization. NPEI's Grid Modernization Strategy has been updated for 2019 and is included in **Error! Reference source not found.**.

NPEI made significant progress implementing technology over the past 5 years. To date NPEI has:

(a) Eliminated all archaic electromechanical reclosers and installed electronically controlled vacuum reclosers. These devices included integrated smart relays for control and monitoring purposes with provision for communication.
(b) Built and deployed a wireless point-to-multi-point network (WiMAX network) utilizing a communications Industry Canada's allocated 1800-1830 MHz bandwidth. To date, 90% of the back-bone network is in service, this includes three (3) towers and nine (9) base stations.

(c) Installed and Commissioned smart end point devices at twelve (12) key locations on our distribution system communicating through our WiMAX network. This includes six (6) MS/DS substations, five (5) reclosers/sectionalizers, and one (1) DER generator.

In addition to the items listed above, NPEI also made significant progress and upgrades related to our SCADA system. This includes:

- Implementing a Disaster Recovery Plan by achieving redundancy in our SCADA server
- Upgrading to a new SCADA HMI platform
- Introduced our WiMAX network end point devices into our SCADA software. Previously, the WiMAX end point devices were viewed using HMI software separate from our SCADA software used for TS Station monitoring. Combining these two technologies allows for easier monitoring and control for our Control Room as well as better historical data for NPEI.
- Developed a standard implementation for monitoring and control of new DER connections.

NPEI plans to continue to invest in our grid modernization by continuing projects and goals set out in our previous DSP. This includes:

1. Completing the wireless point-to-multi-point network back-bone to ensure any end point device installed in our System can access this network.
2. Installing end point devices at our remaining Municipal Stations and reclosers. Prioritizing on stations and reclosers that will provide NPEI with the most control and flexibility.
3. Incorporating all new end point devices and DER connections into our new SCADA HMI system.

In addition to expanding and completing grid modernization plans from our 2014-2019 DSP, NPEI also plans to invest in the following areas of Grid Modernization:

1. Installation of smart Line Fault Indicators at key intersections within our system. These devices are installed on 3 phase lines, typically at tie points along main feeders. The endpoint devices can be connected into our SCADA system via our WiMAX network. The devices will help NPEI in two major areas:

    a. **Line Fault Detection:**

       In certain areas within our territory when an outage occurs, it can be difficult to locate the problem without patrolling the lines. These devices will reduce the down time and assist our crews in locating faults.

    b. **Line Current Monitoring:**

As the devices will be tied into our SCADA monitoring system, it will allow our Control Room to monitor line current in real time at mid points along a Feeder. Traditionally, live Feeder monitoring was only achievable at Substation breakers and mid stream reclosers. Having this new data will help validate our system model for Load Flow studies and help ensure loads are balanced between phases.

2. With the new software improvements implemented into our SCADA system, NPEI will have better historical data available on our distribution system. The new data will help improve our system model for Load Flow studies, assist with Connection Impact Assessments of new DG connections, and provide another tool to be used for system planning. The new SCADA improvements may also lead to enhancements in our Outage Management System (OMS) as we begin to incorporate new devices and monitoring into our OMS. This will assist our Control Room and decrease restoration time during outages.

5.4.0.2.6 Accommodation of Forecasted REG

The accommodation of renewable energy generation projects is not expected to drive any significant system developments over the next five years. During implementation of investments in System Access, System Renewal, System Service, and General Plant initiatives, considerations for REG will be undertaken.

5.4.1 Capital Expenditure Planning Process Overview

This section provides a high level overview of NPEI's capital investment planning process. The capital investment planning process is embedded within NPEI's Asset management process and focuses on determination of which investments are included in the current budget year. The objectives of NPEI's capital expenditure planning process is to address the needs resulting from internal drivers, external drivers, and strategic business objectives.

5.4.1.0 Capital Planning Cycle

The annual Asset Management capital planning investment cycle consists of five general steps as seen below:

Figure 5- 42: Capital Expenditure Planning Process

Capital expenditures are selected and prioritized for implementation once all mandatory expenditures (i.e. System Access) have been accommodated in the budget plan. The basic process is as follows:

1. Determine Capital Investment Needs
   Capital investment needs are determined based on several key drivers. These key drivers represent the input to the process. The drivers used are; customer feedback, reliability data, Asset Condition Assessment, results of system studies, Regional Plans, DG forecasts, climate change adaptation, grid modernization, business needs and technology needs.

2. Capital Plan Development – Forecast Capital Expenditure
   Once the need for capital investments are identified, the next step is to forecast these needs in terms of activity volume, resources, timing and cost. The projects are prioritized and paced.

Projects not prioritized for the current budget year are held over to future years. The output of this process is a project plan typically in the form of an annual budget.

3. Capital Plan Attestation

   The expenditure attestation process involves review of each proposed investment by NPEI senior management. This control measure ensures that the investment portfolio is appropriately aligned with NPEI's vision and strategic objectives. It also ensures that appropriate risk mitigation strategies are deployed within the investment portfolio.

   The attestation process is iterative and allows senior management to request re-prioritization and selection of investments to achieve greater alignment to strategic objectives. Once a final investment portfolio is identified, it forms the capital business plan and becomes part of the annual capital and operating budget. The annual capital and operating budget are presented to the Finance Committee for review and approval.

4. Capital Plan Approval

   NPEI's Finance Committee reviews the capital investment plan and consideration is given to:

   - alignment with strategic goals
   - mitigation of business risk
   - impact on customers
   - benchmark against historical expenditures

   Upon approval of the capital investment plan, the capital and operating budgets are forwarded to the Board of Directors for review and approval. Once approved by the Board of Directors, the capital investment plan is moved to the work execution process.

5. Work Execution

   The work execution plan considers project dependencies (project phasing), labour and material constraints, and externally driven deadlines. A work execution plan is presented to management staff in the Operations department at the onset of the business plan deployment.

   Work execution progress is tracked by the Director of Engineering, Purchasing Manager, and the Director of Operations. Progress is tracked in a centralized database.

   The open projects reports are reviewed by project stakeholders at monthly meetings to ensure adherence to the plan.

6. Continuous Improvement

   A project close out meeting is held following the work execution phase. The meeting captures lessons learned and potential opportunities for improvement moving forward. Opportunities for improvement are reviewed by management to determine if changes to internal processes are required.

A detailed breakdown of the planning process for capital expenditures is shown in the figure below:

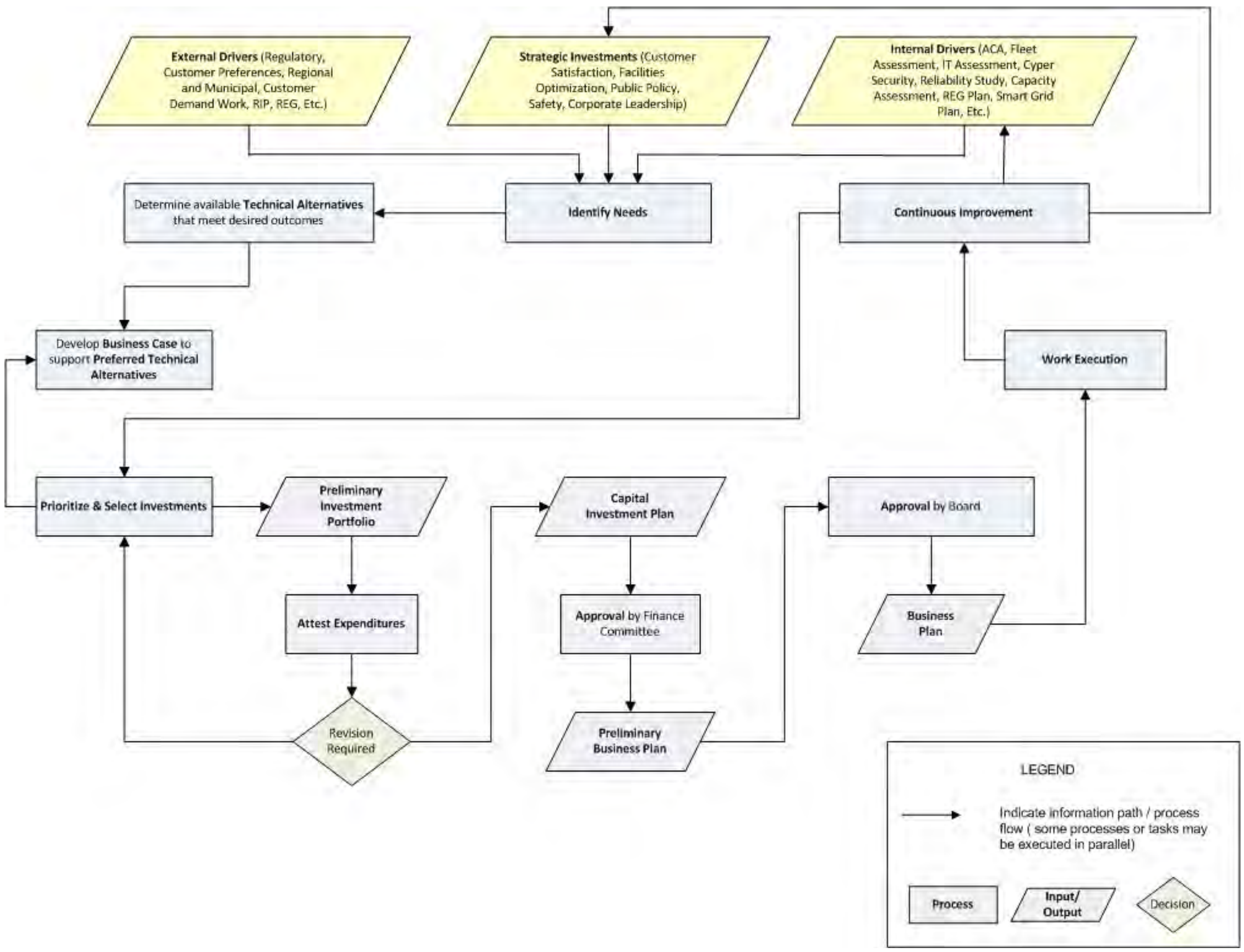


Figure 5- 43: NPEI's Asset Management Process

5.4.1.0.1 Planning Objectives, Assumptions and Criteria

NPEI evaluates proposed projects utilizing a risk/benefit matrix which takes into consideration the Project Category; Efficiency, Customer Value & Reliability; Safety; Cyber Security & Privacy; Co-Ordination & Interoperability; and Environmental Benefits.

A sample of the risk / benefit matrix is shown below:

Project	Project Category				Efficiency, Customer Value, Reliability				Safety				Cyber security, Privacy				Co-ordination, Interoperability				Environmental Benefits				Conservation and Demand Management				Total
	SA	SR	SS	GP	High	Med	Low	N/A	High	Med	Low	N/A	High	Med	Low	N/A	High	Med	Low	N/A	High	Med	Low	N/A	High	Med	Low	N/A	
	4	3	2	1	3	2	1	0	3	2	1	0	3	2	1	0	3	2	1	0	3	2	1	0	3	2	1	0	
	Heading Multiplier			3	Heading Multiplier			0.9	Heading Multiplier			1	Heading Multiplier			1	Heading Multiplier			0.75	Heading Multiplier			0.8	Heading Multiplier			0.5	
Kalar TS Switchgear	x					x					x			x				x						x				x	18.3
South Niagara Feeders ph1	x					x					x					x	x							x				x	17.05
Subdiv Lots	x				x						x					x	x							x				x	17.95
Subdiv Conn	x				x						x				x		x							x				x	18.95
Demand	x				x						x				x		x							x				x	18.95
Metering - General	x					x					x			x				x						x		x			19.3
Road Relocation	x						x			x						x	x							x				x	17.15
McRae Rebuild Ph2		x			x				x							x		x					x					x	17
King St - Rebuild Phase 2		x			x				x							x		x					x					x	17
Cherryhill Rebuild		x			x				x							x		x					x					x	17
Prospect-Brittania-Kitchener		x			x				x							x		x					x					x	17
Cooper-Jill-Jordan-MarieC rebld		x			x				x							x		x					x					x	17
Sixteen Rd Rbld 14 to McCullum		x			x				x							x		x					x					x	17
RR14 Rd Rbld 16 to Twenty Rd		x			x				x							x		x					x					x	17
Padmount Small Tx Replace		x				x				x						x		x				x						x	15.9
Polemount Tx Replace		x				x			x							x		x					x					x	16.1
Pole Changeouts		x					x		x							x		x					x					x	15.2
Lundys Ph1 Mont. to 800177		x			x						x					x	x							x				x	14.95
Switchgear		x				x				x						x		x						x				x	14.3
Subdiv Rehab Ph 3		x					x				x					x	x							x				x	13.15
Kiosks		x			x				x							x			x					x				x	15.45
Sustainment			x			x					x					x			x				x					x	10.35
Fmr Sub Pad Replace		x					x			x						x			x				x					x	13.45
Smart Grid			x				x				x		x						x				x				x		12.95

Figure 5- 44: NPEI's Project Risk / Benefit Assessment Matrix

5.4.1.0.2 Planning Objectives

NPEI planning objectives are governed by the following principles:

- focus on the customer, efficiency, reliability, cyber security;
- sustain operational efficiency (increased functionality, visibility, and control of the distribution system to allow for improved operation and increased DG interconnection); and
- comply with codes, standards, regulations and seek environmental benefits.

NPEI’s planning objective can be summarized as determining the optimum level of investment and configuration of distribution capacity while having due regard to:

- alignment with corporate objectives and asset management strategy;
- meeting safety and regulatory requirements;
- meeting customer demand and expectations;
- minimizing rate impacts;
- coordination with road authorities, local developers and municipalities;
- planning for future growth;
- investing in programs to maintain system reliability;
- modernizing the distribution grid; and
- upgrading and refreshing general plant assets.

5.4.1.0.3 Planning Assumptions

The following key assumptions form the basis of the development of this DSP:

- historical trends will continue unless information is available otherwise;
- level of activity in Distributed Generation will continue; and
- external assumptions such as growth input from regions, municipalities and developers are held constant and up to date.

5.4.1.0.4 Planning Criteria

In terms of the overall planning criteria, NPEI, like most Ontario utilities, has adopted a deterministic or redundancy standard for distribution system planning. The redundancy standard will trigger an investment when the capacity of an asset, such as a station transformer, is exceeded under normal or contingency operating conditions depending on the type of asset. Redundancy, in terms of capacity, is built into the distribution system to deal with unique contingency situations. However, customers will experience an interruption, upon loss of a distribution system element, while backup capacity is engaged, or an asset is replaced. Outage time is also impacted by the level of distribution automation present in the system.

NPEI, like other distribution utilities strives to ensure its distribution system provides a reliable level of service to existing customers and connection capacity for forecasted demand growth and as such must be able to handle customer supply needs during normal and certain contingency situations. Overloading of distribution equipment, as a result of inadequate investment, is avoided as much as possible.

Key Planning Criteria Overview

The planning criteria assume:

- that equipment maintenance, refurbishment and replacement programs are in place to ensure that the capacity and capability of the distribution system is maintained at reasonable level of risk of disruption due to lifecycle related equipment failure; and
- that incidences of extreme weather will continue to be manageable under existing standards of design and construction.

The following is a summary of NPEI's key criteria and planning guidelines:

Table 5- 34: Summary of NPEI’s key criteria and planning guidelines

Criterion	Planning Guideline
General	In planning the system, “good utility practice” shall be followed.
System Voltages	Niagara Falls is 13.8 kV & 4.16kV, Fonthill is 27.6kV & 4.16kV, NPEI's West area is 27.6 kV & 8.32kV
Transformer Stations	TS planned loading shall be to the nameplate rating of one of the station transformers. Under normal situations, station transformers will be loaded up to 50% of their nameplate rating. A station transformer can be loaded up to 120% of nameplate for 2 hours a day for 60 days to allow for transmission/transformer contingency capability.
Distribution Stations Municipal Stations	Distribution Stations (DS) will be 27.6 kV primary supply. The DS secondary supply voltage shall be 8.32kV. DS transformer size shall be 5MVA. Long term strategy is to convert 8.32kV plant to 27.6kV and eliminate the DS. DS Transformer planned loading shall be 100% of normal nameplate rating. DS Transformers maximum allowable loading, under normal conditions shall be their ONAN or ONAF ratings. The distribution system shall be constructed and configured to allow for DS transformers to be backed up by NPEI's Portable Substation and MS's to be backed up by neighboring MS's in the event of a station contingency situation. The typical number of feeders emanating from a DS or MS shall be 3. Planned average loading of 200 amps per feeder will be used.
Feeders	All 13.8 kV feeders shall be designed for full backup capability over peak loading conditions through the switching of load to an adjacent feeder or multiple adjacent feeders. To facilitate this restoration capability, normal feeder loading will be planned to a maximum of 50% of circuit rating under normal operation. Overhead circuit rating is primarily a thermal rating determination such that the conductor does not sustain significant loss of strength due to annealing over its useful life. Underground circuit ratings are based on applicable cable ampacity ratings based on the type of cable and conditions of installation, to optimize cable loss of life over its lifecycle.
Planning Horizon	The planning horizon shall be 5 years to align with the DSP requirements. Regional planning exercises may identify planning needs in excess of the DSP 5-year planning horizon.

Criterion	Planning Guideline
Distribution Automation	Distribution automation through automatic reclosing is to be provided, when cost justified, to ensure that load lost during single contingencies can be restored in a minimum amount of time. Distribution automation should also be considered during plant rebuild and new construction.
Protection Philosophy	NPEI 13.8 kV and 27.6 kV is primarily an overhead distribution system. Feeder protection shall incorporate appropriate auto reclose settings to mitigate the impact of transient faults. In certain circumstances the auto reclose setting will be disabled where all faults on the circuit are expected to be permanent in nature, e.g. feeders with underground cable only. Trip saving protection will be enabled to allow fuses and reclosers to isolate faults where they provide the first line of protection.
Distribution Transformers	Distribution transformers with a normal residential load profile can be loaded up to 150% of nominal rating. For other loads, 130% of nominal rating.
Fleet and tools	Replacement of fleet vehicles and tools shall be scheduled and prioritized to ensure the reliable and timely execution of maintenance and capital expenditure programs.
IT Systems and Infrastructure	Procurement of new IT systems shall consider commercial off the shelf systems with a focus on configuration rather than customization. Cyber security shall be considered in procuring or deploying IT systems.
Equipment Asset Management	Equipment shall be procured, installed, maintained and disposed of through NPEI's Asset Management process.

5.4.1.0.5 Process, Tools, and Methods

Project Identification

The projects that NPEI selects for its capital budget are the ones that promote safety, efficiency, and reliability of its distribution system to allow NPEI to carry out its obligation to distribute electricity within its service area as defined by the Distribution System Code.

System Access projects such as servicing new developments and municipal plant pole relocation projects are identified throughout the year by way of engagement with external proponents. These projects are mandatory in nature and are budgeted and scheduled to meet the timing needs of the external proponents.

System Renewal projects are identified through NPEI's Asset Management process. The project needs for a specific period are supported by a combination of asset inspection, individual asset performance, and asset condition assessments as summarized in the Asset Management Plan.

System Service projects are identified through NPEI's Asset Management process and operational needs to ensure that any forecasted load changes that constrain the ability of the system to provide consistent service delivery are dealt with in a timely manner.

General Plant projects are identified through NPEI's Asset Management process and internally by specific departments (engineering, finance, operations, administration, IT, etc.). These projects tend to be routine investments such as vehicle replacement and technology updates, etc. Special projects are supported through specific business cases for the identified need.

Project Selection and Prioritization

Mandatory projects are automatically selected and prioritized based on externally driven schedules and needs. System Access projects fall into this category and may involve multi-year investments to meet proponent needs. Road widening projects requiring pole line relocation are examples of this.

Remaining capital investments are selected and prioritized based on benefit and risk mitigation for each project with consideration to project cost and annual budget allocation. Most System Renewal, System Service and General Plant projects fall into this category and some projects may involve multiyear program investments to meet Asset Management Objective needs. The current prioritization tool's primary goal is to provide a list of prioritized projects within a given budget that would return that greatest benefit to the utility based on the identified risks to be avoided or mitigated.

NPEI's project selection matrix calculates the overall project score with respect to NPEI's Asset Management Objectives. The calculated project score is an index to measure the value of each capital project to other capital project values. These projects are then prioritized based on NPEI's resource capability and external factors.

5.4.1.0.6 REG Investment Prioritization

The prioritization process for REG expansions is the same as for distribution system expansion projects where the REG expansion is triggered and driven by customer requirements.

When NPEI is required to do an expansion or enhancement to the distribution system to connect an embedded generation facility, the provisions of the *OEB DSC* will apply. NPEI will perform an economic evaluation to determine the generator's share of the present value of the projected capital costs and ongoing maintenance costs of the expansion.

5.4.1.0.7 Assessing Non-Distribution System Alternatives to Relieving System Capacity

NPEI does not at present have any identified system capacity constraints. NPEI actively participates in the Regional Planning process to identify any system capacity or operational constraints. NPEI would work with regional distributors and transmitters to resolve any issues identified.

NPEI notes that non-distribution investments to relieve capacity or operational constraints need to be optimal solutions. The solution must be optimal with respect to the uncertainty of future system loading. The non-distribution system investments need to ensure that distribution system investments can be deferred by a specific time with certainty. Future uncertainties about local distribution capacity demand need to be factored into the value of the non-distribution system investment.

NPEI is open to working with DER proponents on future "non-wires alternatives"

5.4.1.0.8 System Modernization

Grid modernization includes technological improvements to aid in situational awareness (for customers and utility), responding to outages and cyber attacks, defending the grid, controlling the grid, and enabling integration of distributed energy resources. The following are strategies or initiatives NPEI uses / has used in taking advantage of opportunities that arise during system planning to implement cost effective modernization.

- NPEI has implemented technical solutions in a manner that responds to identified customer preferences: customers have access to consumption and usage information, outage information including map and number of accounts impacted and bill information. Self- service user friendly tools are readily available for customers to open an account, change account information, apply for payment plans, view usage and billing information and ask questions. Internal utility staff have tools available to assist customers in reporting outages, establishing restoration timeframes, and provide distribution system status. Solutions meet customer satisfaction. Through the use of customer engagement, NPEI can respond to the needs and requirements as received from the customer.
- Included in NPEI's distribution planning process for system renewal projects are considerations for increasing feeder capacity, replacing transformers and renewing fused switchgear with programmable fault setting capability, adding remote switching devices (reclosers) for feeder segmentation, and implementing alternative means to monitor and control DERs. These initiatives will serve to facilitate greater penetration of DERs.
- NPEI has considered and in some cases implemented several technology-enabling opportunities increasing operational efficiencies, improving asset management or enhancing services to customers. These include; ongoing implementation of a licensed OT communications network (WiMax), automated field switching devices (reclosers), and a web based public facing outage map, integrated to the outage management system which utilizes communications with the deployed smart meters. Initiatives planned for implementation include; customer self-service web forms for service upgrades and new services, end of life replacement of fleet deployed laptops with tablet technology to facilitate easier data collection and incorporation of asset condition photos into work tickets for quality assurance and record purposes.

NPEI also plans to modernize its grid by replacing assets that no longer meet NPEI's design standards with assets that will contribute to operational efficiencies where applicable, such as automated reclosers and smart fault indicators. In addition, NPEI has plans to continue making investments within its IT software and hardware infrastructure. Investing in IT allows for NPEI to maintain its operation and adopt new services and technologies to continue providing excellent service to its customers.

5.4.1.1 Rate Funded Activities to Defer Distribution Infrastructure

The Ontario government announced on March 21st, that CDM programming was being wound down at the LDC level and transferred to the IESO. Accordingly, CDM expenses are not included in NPEI's expenditure forecasts through the DSP forecast period. In the meantime, NPEI continues to monitor its very successful CDM program to ensure all existing approved projects achieve fulfillment by 2020 and that all additional projects are directed to the IESO for extra incentive funding.

As part of the overall asset management strategy, whenever area rebuilds are taking place, NPEI reviews the existing conductor size and the system voltage utilized. If cost effective and feasible, primary conductors are upgraded and voltage conversions undertaken as part of the overall area rebuild in order to maximize efficiency gains and reduce distribution losses.

To date, NPEI has not completed any energy storage projects, however, we have had several enquiries from interested customers. NPEI is a willing host and will work with interested customers to assist them with integrating energy storage into NPEI's system.

5.4.2 Capital Expenditure Summary

The Capital Expenditure Summary provides a picture of NPEI's actual and planned capital expenditures. The capital project expenditures over the five historical years and one bridge year (2015 - 2020) and the five forecast years (2021 - 2025) are categorized as System Access, System Renewal, System Service, or General Plant based on primary investment drivers. The following tables summarize the Capital Expenditures from 2015 to 2025:

Table 5- 35: Capital Expenditure Summary - Historical

Category	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge
System Access	7,462.92	6,489.73	5,701.04	5,992.90	7,863.44	9,487.57
System Renewal	4,176.06	5,625.55	5,534.91	5,256.22	4,031.84	4,246.68
System Service	1,844.56	1,732.73	1,258.51	1,391.88	1,682.78	1,201.75
General Plant	1,538.20	1,578.42	2,438.55	2,344.91	3,369.13	2,628.20
Total	**15,021.73**	**15,426.43**	**14,933.02**	**14,985.91**	**16,947.19**	**17,564.20**
System O&M	**6,656.26**	**6,614.44**	**7,392.39**	**7,047.40**	**7,664.25**	**7,416.00**

Table 5- 36: Capital Expenditure Summary - Forecast

Category	2021 Test Year	2022	2023	2024	2025
System Access	8,465.68	6,346.81	6,490.12	5,196.30	5,197.25
System Renewal	6,828.18	7,986.28	7,314.19	8,155.87	8,348.47
System Service	1,097.81	1,099.07	1,350.33	1,602.22	1,600.33
General Plant	1,550.98	1,550.98	1,550.98	1,550.98	1,550.98
Total	**17,942.65**	**16,983.15**	**16,705.63**	**16,505.37**	**16,697.03**
System O&M	**7,376.56**	**7,524.09**	**7,674.57**	**7,828.07**	**7,984.63**

It is evident, from Figure 5-44 below, that NPEI has been largely investing in System Access projects during the Historical period. This has been accommodated by a corresponding reduction in System Renewal spending through the deferral of planned System Renewal projects. Over the forecast period, System Access spending experiences a decrease in spending and is estimated to be 37% of total spending, accounting for the expected growth within NPEI's service territory. System Renewal spending experiences the largest increase and is estimated to be 46% of the total spending. The increase is a reflection of the deferral of System Renewal work in the historical period which is now required to be executed each year to address the aging infrastructure and maintain system reliability. System Service accounts for a slight decrease to 8% of the total spending, as well General Plant experiences a slight reduction to 9% of the total spending.

There are no expenditures for non-distribution activities in NPEI's proposed budget.

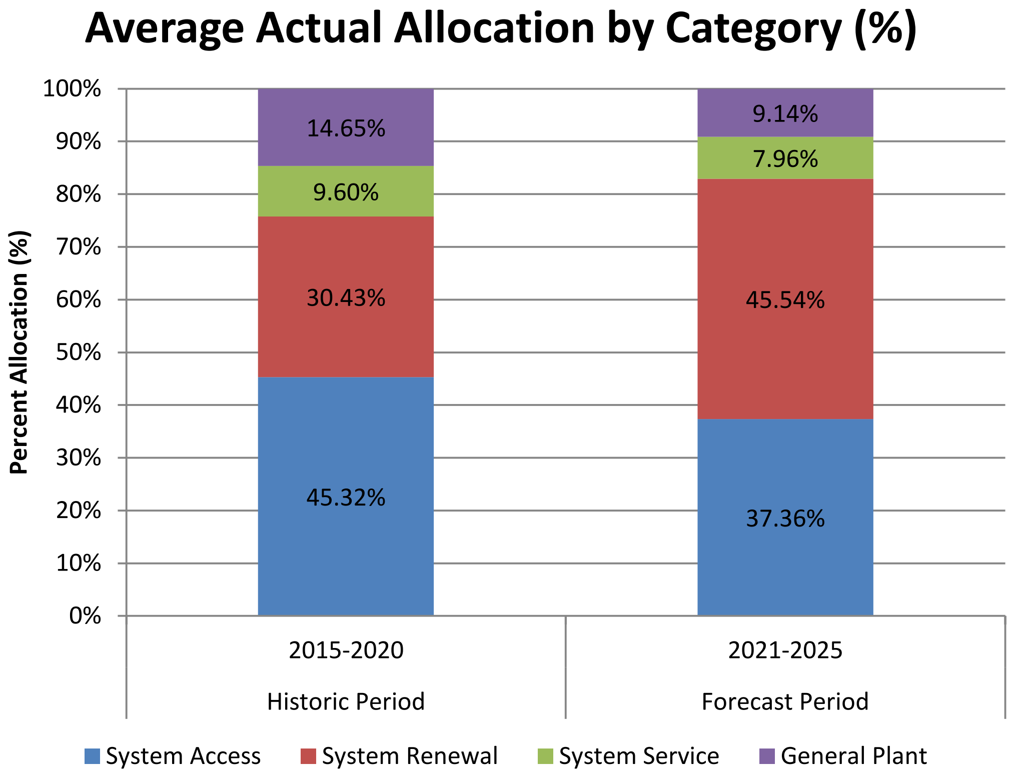


Figure 5- 45: Average Budget Allocation by Category (%)

5.4.2.1 Comparison of OEB Approved DSP Plan vs. Actual for Historical Period by Category

Table 5- 37: Plan vs. Actual Capital Expenditure Summary - Historical

CATEGORY	2015			2016			2017			2018			2019			2020 (Planned)		
	Plan**	Actual	Var	Plan**	Actual	Var	Plan**	Actual	Var	Plan**	Actual	Var	Plan**	Actual	Var	Plan^	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	2,429	7,463	207%	2,249	6,490	189%	1,821	5,701	213%	1,933	5,993	210%	1,663	7,863	373%	9,488	9,488	0%
System Renewal	6,383	4,176	-35%	4,161	5,626	35%	5,889	5,535	-6%	7,301	5,256	-28%	7,223	4,032	-44%	4,247	4,247	0%
System Service	926	1,845	99%	3,760	1,733	-54%	2,449	1,259	-49%	769	1,392	81%	1,330	1,683	27%	1,202	1,202	0%
General Plant	1,447	1,538	6%	1,434	1,578	10%	1,352	2,439	80%	1,204	2,345	95%	1,311	3,369	157%	2,628	2,628	0%
TOTAL EXPENDITURE	11,185	15,022	34%	11,604	15,426	33%	11,511	14,933	30%	11,207	14,986	34%	11,527	16,947	47%	17,564	17,564	0%
Capital Contributions	(828)	(5,600)	577%	(828)	(4,031)	387%	(828)	(2,471)	199%	(828)	(2,538)	207%	(828)	(5,463)	560%	(3,854)	(3,854)	0%
Net Capital Expenditures	12,013	9,421	-22%	12,432	11,395	-8%	12,339	12,462	1%	12,035	12,448	3%	12,355	11,485	-7%	13,710	13,710	0%
System O&M	6,846	6,656	-3%	6,983	6,614	-5%	7,123	7,392	4%	7,265	7,047	-3%	7,410	7,664	3%	7,416	7,416	0%

* Includes 0 months of actual expenditures

** Plan amount corresponds to the previous DSP planned expenditure filed in the last OEB-approved rebasing application

^ Plan amount corresponds to the capital budget amount as the Bridge year was not included in the previous DSP submission

The table above shows the variances of amounts carried in the most recent OEB approved DSP plan versus actual expenditures by category over the Historical period from 2015 to 2020. The tables below (Chapter 2 Appendix 2-AA) summarize the project expenditures by category over the Historical period.

Table 5- 38: Chapter 2 Appendix 2-AA – System Access

Projects	Ref #	2015	2016	2017	2018	2019	2020 Bridge Year	2021 Test Year
System Access								
Customer Driven System Reinforcements for New Commercial Service Connections	1	849,329	736,317	933,983	1,104,336	1,022,512	2,003,964	2,301,448
Commercial Connection Projects Less Than Materiality	2	835,479	1,243,722	1,019,677	1,428,763	1,509,202		
King St. Bell Joint Use Pole Replacement	3	241,068						
NRWC Wind Farm Line Conflicts	4		607,961					
Enercon Wind Farm Line Conflicts	4		430,071					
Eptcon Stringing Conflicts	4		279,261					
FWRN LP Line Conflicts	4		210,545					
Oldfield Rd 3-Ph Pole Line	5		293,937					
McLeod @ Montrose & Oakwood	6			166,310				
Fallsview Entertainment Complex	7				204,129			
Garner Road Line Rebuild to 3-Phase	8					223,044		
Motor Vehicle Accidents	9	80,382	115,958	258,091	179,628	147,214		
Metering	10	111,450	138,789	601,441	585,648	481,484	397,300	405,050
Warren Woods Subdivision Phase 3	11	172,667						
Oldfield Estates Subdivision Phase 1	11	160,905						
Oldfield Estates Subdivision Phase 2	11		183,381					
Warren Woods Subdivision Phase 4	11		171,972					
Warren Woods Subdivision Phase 4 Stage 2	11			184,983				
Warren Woods Subdivision Phase 5	11				237,427			
Cherry Heights Extension	11					341,970		
Vista Ridge Phase 1	11					237,541		
Warren Woods Phase 5 Stage 2	11					166,032		
Terravita Subdivision	11					148,562		
New Subdivision Projects Below Materiality	11	464,908	476,663	340,921	448,833	660,564		
New Connections in Existing Subdivisions	11	395,224	564,008	577,899	333,345	429,566	901,692	915,516
Transfer of Expansion Facilities from Customers	11	3,160,319	688,452	901,555	913,711	2,312,132	1,000,000	1,000,000
Road Relocation Projects	12	411,612	142,942	93,777	125,864	120,412	54,390	540,923
RMN - Reg Rd #18-Mountain Relocation	12	311,300						
CNF Level St U/G Relocate	12	230,733						
Clifton Hill Primary Upgrade	13		309,573					
KM3 - Link	14					11,092	876,668	
Pin Oak Main Loop	15						1,224,075	
GPI Feeder Build	16						807,178	
Thorold Stone - Bridge Roundabout	17						452,235	
Jordan UG Relocate	18						1,062,995	
RR20 Roundabouts	19						254,825	
Fallsview UG Relocate	20						452,244	
Kalar TS Additional Switchgear	21					110,321		1,699,597
Niagara South Feeders Ph 1								1,603,149
Miscellaneous	22	37,540	(103,819)	622,403	431,220	52,114		
Sub-Total		7,462,916	6,489,732	5,701,039	5,992,903	7,973,762	9,487,566	8,465,683

As can be seen from the above table, the variance over the OEB Approved plan for System Access expenditures averaged at 219% of Plan over the Historical Period and was driven each year by customer requested connections and expansions along with municipal road relocation work. All of this work is mandatory for NPEI to complete and outside of our control.

Table 5- 39: Chapter 2 Appendix 2-AA – System Renewal

Projects	Ref #	2015	2016	2017	2018	2019	2020 Bridge Year	2021 Test Year
System Renewal								
Crawford St. Rebuild - Thorold Stone to Sheldon	23	463,166						
Willodel Rd. - Gonder to Koabel	24	313,261						
Willoughby Dr. - Main to Cattell	25	12,799	458,729					
Willoughby Dr. - Cattell to Weinbrenner	26		375,385	318				
Transformer Replacements - PCB > 50 ppm	27	235,322						
Downtown core PILCDSTA Decommissioning	28		382,899	469,444	53,355	75,377		
Station 22 Rebuild - Ph 1 Carryover / Phase 2	29	682,135	202,992					
Beck Road Rebuild - Marshall to Schisler	30	170,696						
Frederica St Rebuild - Dorchester to Drummond	31	14,696	689,884	26,365				
NS&T ROW - Crossing the QEW	32		207,136	159,229				
Jordan Rd Rebuild Phase 2 - Honsberger from Jordan to Thirteenth	33	460,242						
Jordan Rd Rebuild Phase 3	33		307,408					
Jordan Rd Rebuild Phase 4	33			582,371				
Kalar TS Protection Equipment Refurbishment	34			56,943	128,308			
Kalar TS Relay Upgrade	34						75,000	
Dorchester Road Rebuild - McLeod to Dunn	35		377,755	232,048				
Concession 2 Rd - Caistorville Rd to Westbrook Rd	36					157,568		
Thorold Stone Rd Rebuild - Montrose to Kalar	37				10,017	162,768	349,274	
Portage Rd. Rebuild - Mountain to Church's Lane	38				119,863	288,298		
Campden DS Power Tx - Replace with Former Jordan DS Tx	39			35,884				
Station St. DS - Power Transformer Replacement	40			179,626				
Station 14 Voltage Conversion - Phase 1	41			399,195	2,437			
Station 14 Voltage Conversion Phase 2	41				712,832			
Station 14 Voltage Conversion - Phase 3	41					816,054	236,611	
Victoria Ave South of Fly Rd - Phase 1	42		8,936	137,553	694,069			
Victoria Ave South of Fly Rd - Phase 2	42				567,882			
Oakwood Drive - South of Smart Centre to QEW	43			11,808	583,572			
Dorchester Road Rebuild - Mountain to Riall	44		1,943	510,845	204,558			
Chippawa Redundant Supply - Phase 1	45			279,777	67,329			
Chippawa Redundant Supply - River Crossing	45				492,482			
Murray TS - J Bus Metering	46					430,258		
Victoria Ave Rebuild - 7th Ave Phase 2	47					232,172		
Campden DS Tx Failure	48					150,378		
Mountain Road - St. Paul St. to Mewburn	49					297,198		
Sinnicks Ave Rebuild - Thorold Stone to Swayze	50						824,145	
McRae St. Area Rebuild Ph 1	51						351,194	
King St. Rebuild Phase 1 - Bartlett Rd to Sann Rd.	52						344,679	
Cooper - Jill- Jordan - Marie Claude Rebuild								374,856
Prospect - Brittania - Kitchener Voltage Conversion								362,011
King St Rebuild Phase 2 - Sann Rd to Merritt Rd								578,004
Lundy's Lane OH to UG Rebuild - Phase 1								536,750
Sixteen Road Rebuild Regional Rd 14 to McCollum Rd								438,624
Regional Road 14 Sixteen Rd to Twenty Rd								547,178
Cherryhill Rebuild								433,342
McRae St. Area Rebuild Ph 2								466,673
Pole Replacements	53	546,418	583,550	1,009,358	881,938	962,984	700,988	657,323
Kiosk Replacements	54	311,260	1,165,579	937,054	122,613	80,095	52,704	646,096
Switchgear Replacements	55	201,852	222,441	205,352	164,316	308,755	86,218	380,960
Padmount Transformer Replacements								277,762
Polemount Transformer Replacements								410,463
Transformer Collar Replacements								114,635
Pole Mount Step Down Transformer Eliminations - Lincoln / West Lincoln	56						600,106	
Rolling Acres OH to UG Conversion Phase 2	57	764,211						
Rolling Acres OH to UG Conversion Phase 3	57		640,911					
Stanley TS - HONI Initiated	58						625,765	
Subdivision Rehabilitation - Phase 1	59			301,743				
Subdivision Rehabilitation Phase 2	59				450,651	69,938		
Subdivision Rehabilitation Phase 3								603,505
Sub-Total		4,176,057	5,625,547	5,534,913	5,256,221	4,031,843	4,246,684	6,828,182

System Renewal expenditures during the Historical period has averaged 18% below Plan. NPEI has over the years tried to use a total spend approach so that its spending (and distribution rates) are reasonably level and predictable. In order to attain this, NPEI identifies where its spending is to be focused and then balances its annual spend, recognizing that it has resource constraints, both internal and external. During years where customer demand capital requirements (System Access projects) are higher than normal, NPEI will shift resources, where feasible, to reduce its budgeted System Renewal and System Service projects so that its total level of spending remains about the same as budgeted for the year

Table 5- 40: Chapter 2 Appendix 2-AA – System Service

Projects	Ref #	2015	2016	2017	2018	2019	2020 Bridge Year	2021 Test Year
System Service								
King St. 27.6 kV Extension to Martin Rd	60	130,845						
Heartland Road Extension - Brown Rd to Chippawa Creek	61							
Grid Modernization Program	62	143,148	575,200	(47,512)	161,240	225,929	168,450	209,350
Glenholme to Franklin Ave - 600 MCM UG Install	63		68,207	42,618				
Brown Road Extension - Montrose to Blackburn	64			77,945				
Range Road 2 - East of Allen	65				38,951			
System Sustainment / Minor Betterments	66	1,570,562	1,089,323	1,075,854	931,129	1,274,030	873,020	888,460
Willoughby Road Extension	67				259,547			
Kalar TS Power Transformer Dry Down Equipment	68					72,501		
Greenlane Rd at Ontario - Tie Point	69				1,008		160,278	
Sub-Total		1,844,555	1,732,729	1,148,905	1,391,876	1,572,460	1,201,748	1,097,810

System Service expenditures during the Historical period has averaged 13% below Plan. During the Historical Period, customer demand capital requirements (System Access projects) were higher than normal. NPEI shifted resources, where feasible, to reduce its budgeted System Service projects so that its total level of spending remained about the same as budgeted for the year

5.4.2.2 Comparison of Actual Year over Year – Historical Period by Category

Year-over-year variance analysis by investment category is provided below.

Table 5- 41: 2016 versus 2015

Category	2015 Actual	2016 Actual	Variance 2016 vs. 2015
System Access	7,462.92	6,489.73	(973.18)
System Renewal	4,176.06	5,625.55	1,449.49
System Service	1,844.56	1,732.73	(111.83)
General Plant	1,538.20	1,578.42	40.22
Total	**15,021.73**	**15,426.43**	**404.70**
System O&M	**6,656.26**	**6,614.44**	**(41.82)**

System Access

System Access costs for 2016 Actual were ($973K) lower than 2015 Actual.

Prior to 2015, NPEI had not recorded the cost of expansion facilitates transferred from customers which were constructed under the alternative bid option provided for in Section 3.2 of the Distribution System Code.

In 2015, NPEI recorded $3.1M in transferred assets, with offsetting capital contributions, which related to subdivisions energized between 2011 and 2015. In 2016, NPEI recorded $688K in transferred assets, resulting in lower expansion facilities transferred from customers of ($2,471K) compared to 2015 Actual.

New commercial services were $295K higher in 2016, and subdivisions were $202K higher.

During 2016, there was a large wind farm facility installed in NPEI's service area. As a result, NPEI had to relocate distribution plant to accommodate the new generation facility. The costs for these line relocations were $1,528K, all of which was recovered in capital contributions paid by the wind farm developer.

Municipal road relocations were ($811K) lower than 2015 Actual. Material road relocation projects in 2015 are: Regional Municipality of Niagara – Regional Road #18 – Mountain Road for $311K and City of Niagara Falls Level St. Relocate for $231K. There were no material road relocation projects in 2016.

System Renewal

System Renewal costs for 2016 Actual were $1,149K higher than 2015 Actual, mainly attributable to Overhead Rebuilds higher by $513K in 2016 and Kiosk Replacements higher by $854K.

There were 5 material rebuild projects in 2015:

- Crawford St. Rebuild – Thorold Stone to Sheldon = $463K
- Willodell Road – Gonder Rd. to Koabel Rd. = $313K
- Station 22 Rebuild – Phase 1 Carryover = $682K
- Beck Road Rebuild – Marshall Rd. to Schisler Rd = $171K
- Jordan Rd. Rebuild – Honsberger from Jordan to Thirteenth Phase 2 = $460K

There were 7 material rebuild projects in 2016:

- Willoughby Drive – Main St. to Cattell Dr. = $459K
- Willoughby Drive – Cattell Dr. to Weinbrenner Rd. = $375K
- Station 22 Rebuild – Phase 2 = $203K
- Frederica St. Rebuild – Dorchester Rd. to Drummond Rd. = $690K
- NS&T ROW – Crossing the QEW = $207K
- Jordan Rd. Rebuild – Honsberger from Jordan to Thirteenth Phase 3 = $307K
- Dorchester Road Rebuild – McLeod to Dunn = $377K

Several Kiosk Replacements that were deferred from 2015 were completed in 2016:

- 2015 Kiosk Replacement budget = $647K; 2015 Actual = $311K; Variance = ($336K).
- 2016 Kiosk Replacement budget = $841K; 2015 Actual = $1,166K; Variance = $325K.

System Service

System Service costs for 2016 Actual were $112K lower than 2015 Actual.

General Plant

General Plant for 2016 actual was $40K higher than 2015 Actual.

Table 5- 42: 2017 versus 2016

Category	2016 Actual	2017 Actual	Variance 2017 vs. 2016
System Access	6,489.73	5,701.04	(788.69)
System Renewal	5,625.55	5,534.91	(90.63)
System Service	1,732.73	1,258.51	(474.22)
General Plant	1,578.42	2,438.55	860.13
Total	**15,426.43**	**14,933.02**	**(493.42)**
System O&M	**6,614.44**	**7,392.39**	**777.95**

System Access

System Access costs for 2017 Actual were ($788K) lower than 2016 Actual.

Wind farm relocation costs of $1,528K in 2016 did not recur in 2017.

Metering costs for 2017 Actual were $463K higher than 2016 Actual.

In 2014, the Ontario Energy Board provided notice of amendments to the Distribution System Code ("DSC") pursuant to section 70.2 of the Ontario Energy Board Act, 1998. The DSC amendments provide notice that a distributor is required to install an interval meter (i.e. a "MIST" meter) on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW. The DSC requires that MIST meters are to be installed by August 21, 2020. NPEI's 2015 COS Rate Application (EB-2014-0096) included an estimate of 915 conventional meters to be replaced between 2015 and 2020.NPEI commenced the replacement of conventional meters with MIST meters during 2016, continuing in 2017.

The Metering costs for 2017 Actual also include the replacement of 201 interval meters which used legacy 2G cellular communication technology. In the spring of 2017, NPEI received notification from the vendor which provided intermediate communication service for these meters that they would no longer support the metering communication system due to it becoming obsolete in the cellular domain. NPEI identified 225 meters that utilized the 2G network to be replaced in order to avoid possible communication disruptions to these meters that provide energy metering to large commercial customers. NPEI completed 201 of the 2G meter changes in 2017, with the remaining 24 meter changes completed in 2018.

System Renewal

System Renewal costs for 2017 Actual were ($91K) lower than 2016 Actual.

System Service

System Service costs for 2017 Actual were $474K lower than 2016 Actual.

The difference is largely related to NPEI's Grid Modernization Program. During, 2016 NPEI installed a WiMax communications tower at Campden DS in 2016 at a cost of $115K. During 2017, this cost was reclassed from Communication Equipment to Building, to more accurately reflect the estimated useful life of the tower.

General Plant

General Plant for 2017 Actual was $860K higher than 2016 Actual, largely related to Building and Software.

Building expenditures in 2017 include:

- $173K for a new WiMax communications tower in Niagara Falls.
- The WiMax communications tower that was installed at Campden DS in 2016 at a cost of $115K was reclassed from Communication Equipment to Building in 2017, to more accurately reflect the estimated useful life of the tower.

Computer Software additions for 2017 include: Outage Management System upgrades for call taker and a mobile component, upgrade to the outage map, 2 GIS licenses, upgrade of Great Plains accounting system, enhancements to the CIS for change of contacts and Class A, and security upgrades for scan of documents for viruses.

Table 5- 43: 2018 versus 2017

Category	2017 Actual	2018 Actual	Variance 2018 vs. 2017
System Access	5,701.04	5,992.90	291.86
System Renewal	5,534.91	5,256.22	(278.69)
System Service	1,258.51	1,391.88	133.36
General Plant	2,438.55	2,344.91	(93.64)
Total	**14,933.02**	**14,985.91**	**52.89**
System O&M	**7,392.39**	**7,047.40**	**(344.99)**

System Access

System Access costs for 2018 Actual were $292K higher than 2017 Actual, largely due to an increase in new commercial services.

System Renewal

System Renewal costs for 2018 Actual were ($278K) lower than 2017 Actual, largely due to a decrease in Kiosk Conversions of ($818K) and a decrease in Pole Replacements of ($127K), partly offset by an increase in overhead rebuilds of $900K.

During 2018, NPEI reduced the targeted Kiosk Conversions compared to 2017, in order to complete several planned overhead rebuilds.

Material overhead rebuild projects in 2018 include:

- Station 14 Voltage Conversion Phase 2 = $713K
- Victoria Ave. South of Fly Road Phase 1 = $694K
- Victoria Ave. South of Fly Road Phase 2 = $568K
- Oakwood Drive - South of Smart Centre to QEW = $584K
- Dorchester Road Rebuild – Mountain to Riall = $205K
- Chippawa Redundant Supply – River Crossing = $492K

System Service

System Service costs for 2018 Actual were ($133K) lower than 2017 Actual.

General Plant

General Plant for 2018 Actual was ($93K) lower than 2017 Actual.

Table 5- 44: 2019 versus 2018

Category	2018 Actual	2019 Actual	Variance 2019 vs. 2018
System Access	5,992.90	7,863.44	1870.54
System Renewal	5,256.22	4,031.84	(1224.38)
System Service	1,391.88	1,682.78	290.90
General Plant	2,344.91	3,369.13	1024.22
Total	**14,985.91**	**16,947.19**	**1961.28**
System O&M	**7,047.40**	**7,664.25**	**616.85**

System Access

System Access costs for 2019 Actual were $1,871K higher than 2018 Actual, largely due to an increase in subdivisions of $964K and an increase in the transfer of expansion facilities from customers of $1,398K, offset by a decrease in metering costs of ($104K)

System Renewal

System Renewal costs for 2019 Actual were ($1,224K) lower than 2018 Actual, largely due to a decrease in Overhead Rebuilds of ($1,629K) and a decrease in Subdivision Rehabilitation of ($381K), partly offset by an increase in Switchgear Replacements of $144K, and Murray Station J-Bus Metering of $430K.

Material overhead rebuild projects in 2019 include:

- Portage Road Rebuild – Mountain to Church's Lane = $288K
- Station 14 Voltage Conversion Phase 3 = $816K
- Victoria Ave. Rebuild 7th Ave. Phase 2 = $232K
- Mountain Road - St. Paul St. to Mewburn = $297K

System Service

System Service costs for 2019 Actual were $291K higher than 2018 Actual, largely due to an increase in System Sustainment of $343K.

General Plant

General Plant for 2019 Actual was $1,024K higher than 2018 Actual, largely due an increase in building costs of $1,013K, representing the first phase of construction of NPEI's new garage and truck washing facility.

The existing vehicle service garage was designed and constructed within the operations centre at 7447 Pin Oak Drive in 1984 (35 years ago) and was sized and outfitted with equipment that accommodated the requirements of the company fleet complement of the day. Future considerations of the physical size of vehicles and the number of fleet equipment were incorporated into the design at that time, but those capacities and numbers have been exceeded for some years now. On average, the size and weight of the large service vehicles has increased by 30 to 40 percent and the number of vehicles in the fleet has doubled since the garage was designed and built. The garage is now too small to provide for the needed space to service the number of vehicles we have, and the limited capacities of the vehicle hoisting systems have been reached and they are near the end of their useful life. To maintain safe and efficient servicing for our fleet of equipment a new facility is required.

The new Service Garage facility will provide space to accommodate up to, two large and two small vehicles at one time (twice the existing capacity). The hoisting systems will have greater lifting capacities and will incorporate the latest safety technologies. Environmental management features will be incorporated where required and energy efficient systems will be installed to be environmentally responsible and respectful. The new service facility will provide a modern, safe, efficient and environmentally friendly environment to service our complement of vehicles and will support our equipment servicing requirements for decades to come.

Included in the new service garage facility building footprint will be a roughed in truck washing bay. Currently all vehicle washing is performed in the large vehicle parking garage. Washing vehicles in this area results in a perpetually wet environment that creates slipping hazards and accelerates the degradation of the concrete floor. It is anticipated the truck washing facilities will be installed in the future.

Table 5- 45: 2020 versus 2019

Category	2019 Actual	2020 Bridge	Variance 2020 Bridge vs. 2019
System Access	7,863.44	9,487.57	1,624.13
System Renewal	4,031.84	4,246.68	214.84
System Service	1,682.78	1,201.75	(481.03)
General Plant	3,369.13	2,628.20	(740.93)
Total	**16,947.19**	**17,564.20**	**617.01**
System O&M	**7,664.25**	**7,416.00**	**(248.25)**

System Access

System Access costs for the 2020 Bridge Year is $1,624K higher than 2019 Actual, due to an increase in municipal road relocations of $2,156K an increase in new commercial services of $1,562K, GPI Feeder Build of $807K, offset by a decrease in the transfer of expansion facilities from customers of ($1,312K), and a decrease in subdivision costs of ($1,083K).

Material System Access projects in 2020 include:

- KM3 Link = $877K
- Pin Oak Main Loop = $1,224K
- GPI Feeder Build = $807K
- Thorold Stone Rd. – Bridge St. Roundabout = $452K
- Jordan UG Relocate = $1,063K
- Regional Road 20 Roundabouts - $255K
- Fallsview UG Relocate = $452K

NPEI anticipates that the level of subdivision development in 2020 will return to a level more typical of recent years compared to 2019.

System Renewal

System Renewal costs for the 2020 Bridge Year are $214K higher than 2019 Actual, mainly due to an increase in Overhead Rebuilds of $853K, a decrease in Pole Replacements of ($262K), and a decrease in Switchgear Replacements of ($223K).

System Service

System Service costs for the 2020 Bridge Year are ($483K) lower than 2019 Actual, largely due to a decrease in System Sustainment of ($401K).

General Plant

General Plant for the 2020 Bridge Year is ($741K) lower than 2019 Actual, mainly due to:

- A decrease in building costs of ($270K), as NPEI expects the new garage building to be completed in 2020.

A decrease in vehicle costs of ($410K). Vehicle expenditures in 2019 include the replacement of a pick-up truck for $40K, body for a radial boom derrick for $264K, and a mini-track machine for $248K. In 2020, NPEI plans to replace a van for $40K and purchase the chassis of a radial boom derrick truck for $150K.

5.4.3 Justifying Capital Expenditures

This section provides the necessary data, information and analysis to support the capital expenditure levels proposed in this DSP.

5.4.3.1 Overall Plan

5.4.3.1.1 Comparative Expenditures by Category Over the Historical Period

The table below illustrates the proportion of Actual Capital Expenditures in each investment category for the historical period 2015 to 2020. Also included is the Plan or budgeted amount for each year along with the variance of Actual vs. Plan.

Table 5- 46: Historical Expenditures by Category

CATEGORY	2015			2016			2017			2018			2019			2020 (Planned)		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	2,438	7,463	206%	2,683	6,490	142%	3,005	5,701	90%	3,944	5,993	52%	5,973	7,863	32%	9,488	9,488	0%
System Renewal	6,771	4,176	-38%	3,442	5,626	63%	6,587	5,535	-16%	5,776	5,256	-9%	4,726	4,032	-15%	4,247	4,247	0%
System Service	1,028	1,845	79%	4,932	1,733	-65%	1,497	1,259	-16%	1,677	1,392	-17%	1,177	1,683	43%	1,202	1,202	0%
General Plant	1,489	1,538	3%	1,616	1,578	-2%	2,513	2,439	-3%	2,580	2,345	-9%	3,245	3,369	4%	2,628	2,628	0%
TOTAL EXPENDITURE	11,727	15,022	28%	12,673	15,426	22%	13,602	14,933	10%	13,977	14,986	7%	15,122	16,947	12%	17,564	17,564	0%
Capital Contributions	(828)	(5,600)	577%	(800)	(4,031)	404%	(1,537)	(2,471)	61%	(2,135)	(2,538)	19%	(2,187)	(5,463)	150%	(3,854)	(3,854)	0%
Net Capital Expenditures	10,899	9,421	-14%	11,873	11,395	-4%	12,065	12,462	3%	11,842	12,448	5%	12,935	11,485	-11%	13,710	13,710	0%
System O&M	6,620	6,656	1%	6,401	6,614	3%	6,958	7,392	6%	7,005	7,047	1%	7,601	7,664	1%	7,416	7,416	0%
* Includes 0 months of actual expenditures																		

System Access Investments

System Access based investments account for approximately 45% of historical capital expenditures. These investments relate to external drivers such as municipal road works, private development and demand for new connections to the electrical distribution system.

System Renewal Investments

System Renewal based investments account for approximately 30% of historical capital expenditures. The majority of investments in this category are based on the results of the asset condition assessment report. Major programs, apart from overhead line rebuild projects, related to system renewal expenditures were the pole replacement program and kiosk replacement program.

System Service Investments

Approximately 10% of NPEI's historical capital expenditures are in the system service category. These investments were aimed at improving reliability and system efficiency through distribution system expansion and grid modernization expenditures.

General Plant

General plan investments represent approximately 15% of NPEI's historical capital expenditures. The expenditures are related to assets that are not part of the distribution system including buildings, IT infrastructure, vehicles, tools, and equipment.

Figure 5-45 above illustrates the proportion of Capital Expenditures in each investment category for both the Historical and Forecast periods

5.4.3.1.2 Historical Impact of Investments on System O&M Costs

The relationship between capital expenditures and system O&M costs is dependent on the proportion of planned capital expenditure investments in new assets vs. replacement assets. NPEI as a means of controlling O&M costs utilizes a total expenditure (capital plus O&M) balance budget philosophy.

- New vs. Replacement Asset Mix In general, investment in capital programs does not materially impact system O&M costs unless a significant amount of new assets are added to the system which will result in future O&M costs for ongoing upkeep. Investment in System Renewal programs tends to reduce/avoid near-term O&M costs associated with the asset while investment in System Service and System Access programs are typically associated with installation of new/upgraded assets which will increase future O&M costs required to maintain the assets. This relationship is not tracked by NPEI and therefore it is difficult to estimate the historical impact of capital expenditures on system O&M costs.
- NPEI has over the years tried to use a total spend approach so that its spending (and distribution rates) are reasonably level and predictable. In order to attain this, NPEI identifies where its spending is to be focused and then balances its annual spend, recognizing that it has resource constraints, both internal and external. During years where customer demand capital requirements (System Access projects) are higher than normal, NPEI will shift resources, where feasible, to reduce its budgeted System Renewal and System Service projects so that its total level of spending remains about the same as budgeted for the year. As NPEI's system expands and additional infrastructure is installed to accommodate connection of new customers and to accommodate load growth, there will be an associated increase in O&M costs. NPEI whenever possible, will reduce planned capital spending to accommodate higher customer demand connections rather than reduce O&M expenditures. NPEI plans and schedules cyclical maintenance activities such that the annual O&M spend is approximately consistent year over year.

5.4.3.1.3 Forecast Impact of System Investment on System O&M Costs

System investments in each of the system categories will result in:

- the addition of incremental plant (e.g. poles, cable, conduit, vaults, transformers, etc.)
- the relocation/replacement of existing plant (e.g. road authority related work)
- the replacement of end of life plant with new plant (e.g. cables, poles, transformers, etc.)

- new/replacement system support expenditures (e.g. fleet, software, etc.)

In general, incremental plant additions will be integrated into the Asset Management system and will require incremental resources for ongoing O&M purposes. This is expected to put upward pressure on O&M costs.

Relocation/replacement of existing plant normally results in an asset being replaced with a similar one, so there would be little or no change to resources for ongoing O&M purposes (i.e. inspections still need to be carried out on a periodic basis as required per the Distribution System Code). There may be some slight advantages when an older piece of equipment is replaced with a newer one that would impact on O&M repair related charges. Overall the planned system investments in this category are expected to put neutral pressure on O&M costs.

Replacement of end of life assets will still require the allocation of resources for ongoing O&M purposes. Repair would be the most significant O&M activity impacted by new plant. Certain assets, such as poles, offer few opportunities for repair related activities and generally require replacement when deemed at end of normal life or critically damaged. Other assets such as direct buried cable offer opportunities for repair related activities (e.g. splices) up to a point where further repairs are not warranted due to end of life conditions. In a few areas cable faults will not be repaired due to cable end of life. When faulted, the faulted cable section will be replaced, normally a section between two distribution transformers. For planned cable replacement in a subdivision, new primary cable installed in duct replaces direct buried primary cable and is expected to provide higher reliability and life. This will shift response activity for a cable failure from repair (O&M) to replacement (Capital). If assets approaching end of life are replaced at a rate that maintains the existing system's condition, then the expectation would be little or no change to O&M costs under no growth scenarios but would still see upward O&M cost pressure on growth scenarios (more cumulative assets to maintain each year). Replacement rates that improve equipment class average condition could result in lowering certain maintenance activities costs (e.g. pole testing, reactive repairs, etc.). Overall this is expected to put downward pressure on O&M repair related costs.

System support expenditures (e.g. grid modernization and improved SCADA visibility) are expected to provide a better overall understanding and capability assessment of NPEI's assets that will lead to more efficient and optimized design, utilization, maintenance and investment activities going forward. Improved asset information will allow existing resources to partially compensate for growth related increases in O&M activities. Fleet replacement expenditures will result in reduced O&M for new units, however, this will be offset by increasing O&M of remaining units as they get older.

Overall, the system investments are not expected to have a significant impact on total O&M costs in the forecast period.

Table 5- 47: System O&M Impacts

Item	Impact of Growth on O&M	Impact of Relocation on O&M	Impact of Asset Replacement on O&M
Poles	Increase	Neutral	Neutral
Cables	Increase	N/A	Decrease (repairs only)
Vaults, manholes and duct	Increase	N/A	Neutral
UG Transformers	Increase	N/A	Neutral
UG Switchgear	Increase	N/A	Neutral
OH Transformers	Increase	Neutral	Neutral
Meters	Increase	N/A	Neutral
Fleet	Neutral	Neutral	Neutral
Information Technology	Increase	N/A	N/A

5.4.3.1.4 Drivers of Investment by Category

The following sections identify the forecast expenditures by category and the drivers of the respective investments by category.

Table 5- 48: Forecast Expenditures by Category

CATEGORY	Forecast Period 2021	2022	2023 $ '000	2024	2025
System Access	8,466	6,347	6,490	5,196	5,197
System Renewal	6,828	7,986	7,314	8,156	8,348
System Service	1,098	1,099	1,350	1,602	1,600
General Plant	1,551	1,551	1,551	1,551	1,551
TOTAL EXPENDITURE	17,943	16,983	16,706	16,505	16,697
Capital Contributions	(2,583)	(2,585)	(2,587)	(2,589)	(2,587)
Net Capital Expenditures	15,359	14,398	14,119	13,916	14,110
System O&M	7,377	7,524	7,675	7,828	7,985

In comparison of Table 5-48 to Table 5-46, there is a relatively consistent composition of capital expenditures across the investment categories. Towards the end of the Forecast period, NPEI envisions a small reduction in System Access work as the larger projects associated with the New Niagara South hospital and the Canada Summer Games wrap up. Aiming to maintain a consistent overall level of expenditure, the reduction in System Access capital spending would be offset by an increase in System

Renewal expenditure. NPEI anticipates otherwise consistent connection and expansion demands, asset management strategies, and investment alignment with strategic business values.

System Access

System Access investments include the following drivers:

- Customer Demand Requests (System Access) – the Niagara Region continues to be experiencing urban growth requiring new customer connections (both commercial site redevelopment and residential subdivisions). Forecasts assume increased investment needs due to planned urban growth throughout NPEI's service area
- 3rd party infrastructure – Road widening and municipal improvements will require plant relocation.
- Municipal driven projects to accommodate the Canada Summer games in 2021.
- System Expansion work required to accommodate the development of the new Niagara West Hospital.

In summary, due to the forecast employment and population growth in the Niagara Region under the Places to Grow Act, System Access needs in the 2021 – 2025 period will continue to focus on new commercial and subdivision connections, connection upgrades due to site redevelopment, and plant relocation due to urbanization and intensification of the road network. No change in drivers is expected over the forecast period.

System Renewal

System Renewal investments include the following drivers:

- Asset Health Index - Multiyear planned asset replacement programs and area rebuilds that address assets at end of life condition. Historical trend has seen lower investment amounts due to resource reallocation to mandatory System Access investments related to customer demand.
- Failure Risk – Asset replacement programs based on asset inspections to prevent emergency reactive replacement of distribution system assets (poles, transformers, switches, switchgear, cable, conductor, insulators, guys, anchors, etc.) due to unanticipated failure, storms, etc.

In summary, system renewal spending will focus on planned proactive asset replacement programs as identified in the ACA. There will be increased expenditure in this area for the forecast period since several system renewal projects had to be deferred to reallocate resources during the years 2014-2019 to accommodate customer demand driven System Access work. No change in drivers is expected over the forecast period.

System Service

System Service investments include the following drivers:

- System Constraints – Line extensions and feeder interconnections to accommodate grid load growth. Current plans do foresee the need to begin planning for some additional TS/DS capacity over the forecast period.
- System Operational Objectives – Investments to innovation, system reliability and efficiency (i.e. smart fault indicators and reclosers leveraging the WiMax network).

In summary, system service spending will continue to focus on maintaining operational performance and the efficient utilization of system plant. System service budget is higher in the forecast period in comparison to the historical spending due to the continuous deferral of added value projects for nondiscretionary projects. NPEI is proposing to invest in innovative technology that would promote efficiency and improve system reliability in troublesome areas. No change in drivers is expected over the forecast period.

General Plant

General Plant investments include the following drivers:

- System Maintenance Support – Replacement of rolling stock and tools. Historical investments have resulted in specific rolling stock and tool replacement as required. Replacement of major fleet units tends to be a high lumpy cost when compared to the replacement costs of small fleet units. Due to the long lead time for delivery of the large fleet vehicles, the purchase is typically spread over two years. The chassis is ordered in year one with the body fit out in year two. By staggering the investment in large fleet vehicles and strategically incorporating light vehicle replacements, NPEI is able to maintain a relatively stable cost for fleet replacements.
- Business Operations Efficiency – The IT assessment reviews NPEI's IT and OT hardware and software. NPEI plans and manages system and software updates to maximize reliability and cyber security while also levelizing capital expenditure. This approach minimizes the risk to customer information, billing, reporting and recording should a security vulnerability or hardware or software problem develop.
- Non-system Physical plant – Forecast investments focus on renovations and upgrades to NPEI's facility at 7447 Pin Oak Drive in Niagara Falls and station buildings. These investments are driven by asset condition inspections and prioritized based on safety and risk of further damage if repairs are deferred.

In summary, general plant spending will continue to focus on ensuring fleet asset performance meets NPEI operational and reliability needs, software platform upgrades and modernization, and facility works to sustain buildings and lands. No change in drivers is expected over the forecast period.

5.4.3.2 Material Investments

This section provides information regarding material projects for the capital expenditure planning period 2021 to 2025. As calculated in Chapter 2, the threshold for materiality that NPEI is using is $175,000. Project narratives have been prepared for all material capital expenditures planned for the 2021 test year in excess of $175,000 to address the requirements of Section 5.4.3.2 of Chapter 5. These project narratives are included as Appendix A.

Material capital expenditures for the 2021 test year are summarized in the table below.

Table 5- 49: Material Investments Allocated for 2021

Category	Category Total Expenditure $'000	Project Name/Description	2021 $'000	Priority Ranking
System Access	7,465	Meter Installation and Replacement	405	19.3
		Subdivision Connections	490	18.95
		Customer Demand - New services/upgrades	2,301	18.95
		Kalar TS Switchgear	1,700	18.3
		Subdivision Lots	425	17.95
		Road Relocation	541	17.15
		South Niagara Feeders Ph 1	1,603	17.05
System Renewal	6,714	Cherryhill Rebuild	433	17
		McRae Rebuild Ph 2	467	17
		Cooper-Jill-Jordan-MarieClaud Rebuild	375	17
		Prospect-Brittania-Kitchener Rebuild	362	17
		King St. Rebuild ph 2	578	17
		Sixteen Road Rebuild - 14 to McCullum	439	17
		RR14 Rd Rebuild - 16 to Twenty Rd	547	17
		Polemount Tx Replacements	410	16.1
		Padmount Small Tx Replacements	278	15.9
		Kiosk Tx Replacement	646	15.45
		Pole Changeouts	657	15.2
		Lundy's lane UG Cable Replacement Ph 1	537	14.95
		Switchgear Replacements	381	14.3
		Subdivision Rehab Ph 3	604	13.15
System Service	888	Sustainment (System Betterments)	888	10.35
General Plant	670	RBD Truck Replacement	270	--
		NF Service Centre Concrete Floor Repair	400	--
Total	15,737		15,737	--

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Appendix A:
Material Project Justifications – 2021 Test Year

Capital Project Summary

Project Name:	Customer Demand	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Access	**Service Area:**	All

General Information on Project (5.4.4.2.A)

Project Summary	This capital program manages an allowance for the construction/upgrade of distribution equipment to facilitate system access connections of new commercial developments. Expansions and reinforcement to the distribution system resulting from these new customer connection requirements fall under this budget allowance.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$2,301,448.00		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	$1,200,000.00		
	NPEI Estimated Cost:	$1,101,448.00		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	N/A			
Project Dates (5.4.3.2.A.iv)	**Start Date:**	January 1, 2021		
	In Service Date:	December 31, 2021		
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$200,000	$500,000	$800,000	$801,448

Project Name: Customer Demand
Category: System Access

Images, Drawings, Maps, & Other Reference Material

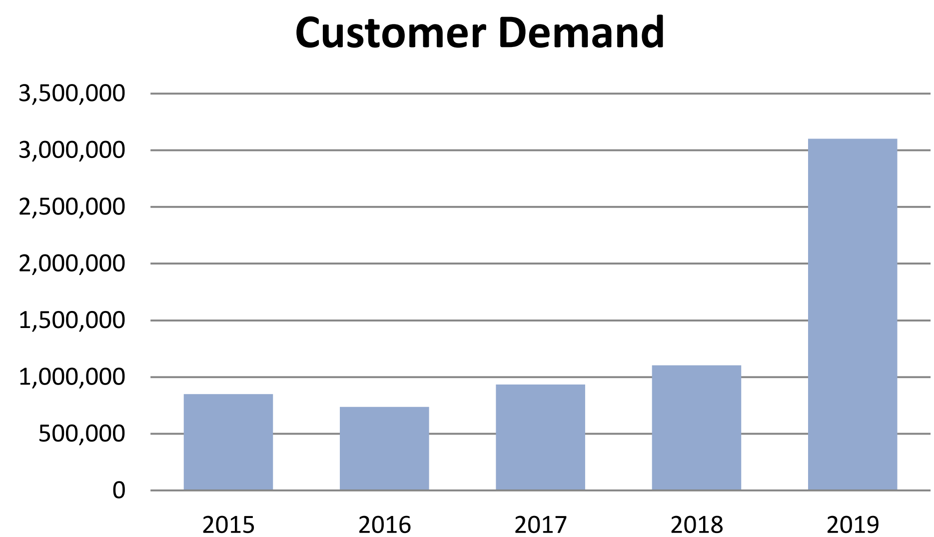
Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The schedule risk for this program lies with the developer and the availability of NPEI's internal resources to design and service the development. The workload is driven by customer demand, which is not steady throughout the year. Another risk to schedule is long lead items such as large transformers and switchgear.

To mitigate risks, NPEI works closely with developers and third parties to ensure a timely service connection. This involves reviewing notices for zoning by-law amendments and reaching out to potential developers. At this time the process is communicated with the developer and time lines are established.

Project Name: Customer Demand
Category: System Access

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)



Historical spending for customer demand has been fairly consistent, but trending upwards. 2019 saw a large increase due to increased development. The development has not slowed and is expected to continue.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not applicable.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary investment driver is customer demand. When a commercial customer plans to upgrade or develop, they apply to NPEI to provide them with an electrical service. Per the Distribution System Code and Conditions of Service, NPEI is required to provide the customer with an Offer to Connect.

Good Utility Practice (5.4.3.2.B.1.b)

Expansions and reinforcement to the distribution system are the result of customer demand. These customers must be supplied within a time line prescribed by the OEB. When large customers are connected to NPEI's grid, the infrastructure is designed in house. NPEI leverages senior staff's years of experience to ensure the distribution system remains resilient and addresses existing reliability and performance concerns.

Project Name: Customer Demand
Category: System Access

Investment Priority (5.4.3.2.B.1.c)

On NPEI's Project Priority Matrix, the investment ranks high as compliance with the Distribution Service Code, adhering to our Conditions of Service and meeting the Ontario Energy Board's service quality requirements for customer requests is mandatory.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The program funding is based on actual connection costs. Typically the investment does not impact system operation efficiency.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Customers benefit by having their development supplied with a new, reliable and service built to current standards. Having more customers on the grid benefits existing customers by reducing distribution rate impacts.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Reliability for the new customer will be excellent, as all the assets are new. Reliability for existing customers may improve if the system requires reinforcements in other areas to support the new customers. This would reduce frequency and duration of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Developers have their own set of requirements such as service size, transformer type and location. NPEI completes the system design and connection based around the developer's requirements as well as NPEI's standards and Conditions of Service. The process is collaborative with regular meetings during the design process.

Scheduling Alternatives:

The schedule is set by the developer with feedback from NPEI.

Ownership Alternatives:

Customers have the option of owning the load transformer.

Safety (5.4.3.2.B.2)

All new commercial and industrial services are installed in accordance with NPEI's standards and meet the requirements of Ontario Regulation 22/04

Larger commercial customers are typically provided with an underground service. This reduces the likelihood of energized wires coming in contact with trees, animals and objects as well as pole structures failing and causing injury or property damage.

Cyber-Security and Privacy (5.4.3.2.B.3)

When new customers set up accounts, all customer information is handled in accordance with established privacy policies and guidelines.

Project Name: Customer Demand
Category: System Access

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This program is coordinated with the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln, the Town of Pelham, the Niagara Region, Bell Canada, Rogers, Cogeco and NRBN.

During the design phase NPEI hosts meetings with developers and third parties to address issues as they arise.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

Not applicable.

Environmental Benefits (5.4.3.2.B.2.B.5)

Not applicable.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

NPEI connects new developers with our CDM department at the design phase to help incorporate efficiency into the building design.

Category – Specific Requirements – System Access (5.4.4.2.C - SA)

Factors Affecting Timing/Priority (5.4.4.2.C – SA.i)

Developer's schedule - Ultimately the work is based around the proposed schedule of the development which is beyond NPEI's control.

Availability of primary - Sections of NPEI's distribution system operate at 4.16 kV as opposed to 13.8 kV. Very large commercial customers will often require 13.8 kV to provide the necessary amount of power. When this is the case, there is a significant amount of work which can take up to a year to complete. NPEI mitigates this factor by coordination its long term distribution plan with the local municipalities and region to understand the areas likely to be developed and make plans to accommodate.

Availability of labour - NPEI utilizes both internal resources and contractors to construct electrical infrastructure for new customers.

Unplanned events - System Access projects rank highest in priority, however in the event of major unplanned outages resources will be allocated appropriately. I there is a higher than usual amount of major events, there is potential for delay.

Factors Related to Customer or Third-Party Preferences (5.4.4.2.C – SA.ii)

The electrical plant for commercial and industrial customers is constructed in response to customer needs via developer requests for new services and service upgrades. NPEI completes the system design and connection based around the developer's requirements as well as NPEI's standards and Conditions of Service. The process is collaborative with regular meetings during the design process.

Project Name: Customer Demand
Category: System Access

Factors Affecting the Final Cost of the Project (5.4.4.2.C – SA.iii)

The final cost is dependent on the specifics of the project. If there is no infrastructure or improper voltage in the area costs can be significantly higher than servicing a customer in a densely populated area where robust infrastructure already exists. Main factors would be underground vs overhead service and running new primary.

Measured used to Minimize Controllable Costs (5.4.4.2.C – SA.iv)

Controllable costs are minimized through the use of standard materials and standardized designs.

Other Planning Objectives (5.4.4.2.C – SA.v)

When the electrical distribution system is being designed to service a large development, often times there is more development slated for the area. NPEI utilizes this opportunity to plan for future load growth.

Other Project Design and/or Implementation Options Considered (5.4.4.2.C – SA.vi)

When the design is underway, NPEI works closely with the developer. Some design considerations would be circuit loading, routing, overhead vs underground service and future loading.

Summary of Result Analysis – "Least Cost", "Cost Efficient" Option (5.4.4.2.C – SA.vii)

NPEI works with the developer during the design phase. Options are provided based on NPEI's standards and Conditions of Service. NPEI and the developers work together to ensure the best interest of the customer.

Economic Evaluation Results (5.4.4.2.C – SA.viii)

Connection costs are chargeable to the developer. NPEI conducts economic evaluations on commercial and industrial developments in accordance with Section 3.2 of the Distribution Code if expansion work is required. The results of the evaluations vary.

System Impacts, Related Costs, and Cost Recovery Methods (e.g. REG investment) (5.4.4.2.C – SA.ix)

Not applicable.

Project Sign-Off

Prepared By:	Weston Sagle	Authorized By:	
Date:	January 28, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	Kalar TS Switchgear	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Access	**Service Area:**	Niagara Falls

General Information on Project (5.4.4.2.A)

Project Summary	Kalar TS is a DESN designed station with dual 45/60/75MVA dual winding transformers. The design supports two lineups of switchgear, though at time of construction only a single lineup on one set of windings was installed. The existing B1B2 bus is capable of supporting a maximum of 2000A or 45MVA of load. The present connected peak load at Kalar TS is approximately 44MVA. This project will install the second set of switchgear, connected to the second set of windings of the existing power transformers. Some feeders will be selected and re-routed from the B1B2 bus to the new switchgear to immediately provide additional capacity for the station.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$1,699,597.44		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	$0.00		
	NPEI Estimated Cost:	$1,699,597.44		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	10,098 customers / 45,894 kVA peak load - 2016			
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 1, 2021			
	In Service Date: December 31, 2021			
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$1,200,000	$300,000	$100,000	$99,597.44

Project Name: Kalar TS Switchgear
Category: System Access

Images, Drawings, Maps, & Other Reference Material

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

There is risk to schedule with ordering the switchgear. The order is custom and there is a long lead time. To mitigate this NPEI is currently issuing an RFP for the supply of the gear. Expected delivery is Q1 of 2021.

Another risk is the availability of labour for the installation. An RFP for installation will be issued once the contract is awarded for material supply. The RFP for installation will be issued approximately May 2020.

There is also risk in installation and commissioning. As this is a complex project, NPEI has hired NBM Engineering to complete the design. It's difficult to anticipate problems that arise during installation and commissioning. As the station cannot be offloaded, the work will be have to be performed while the station is in service.

Project Name: Kalar TS Switchgear
Category: System Access

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

In 2018, NPEI obtained budgetary estimates for the supply and installation of the new switchgear.

Supply, Install and Commissioning
$1,587,000

Switchgear only
$1,070,125

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

This project is not driven by REG investment. However, completion of this project will increase the load carrying capability of the station which will permit new REG to be connected.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

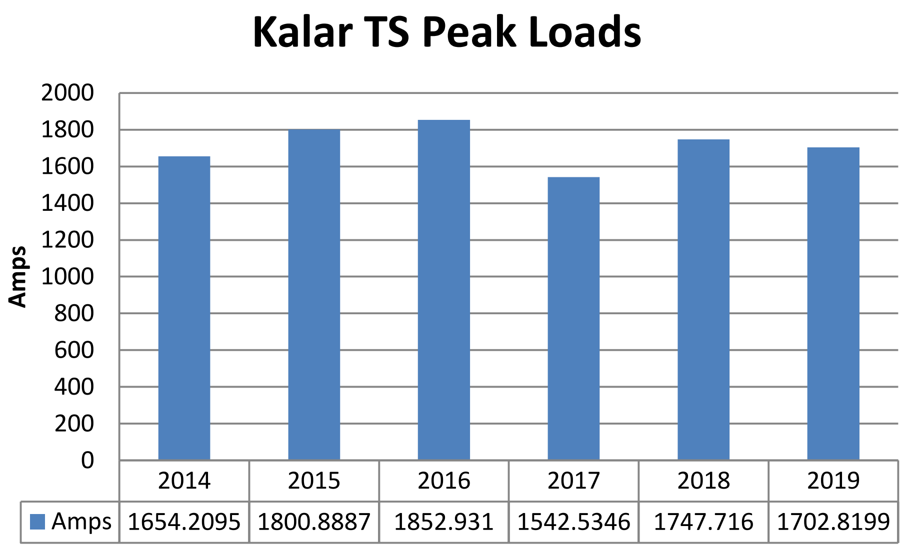
The primary driver for this project is customer demand. When a commercial customer plans to upgrade or develop, they apply to NPEI to provide them with an electrical service. Per the Distribution System Code and Conditions of Service, NPEI is required to provide the customer with an Offer to Connect.

A new hospital is scheduled to complete construction in 2026. Currently, no other substations have capacity to supply the development. The secondary driver is system constraint as the Kalar TS has reached capacity. Kalar was originally built with provisions for a second line up of switchgear. In the substation there is dedicated space for the new switchgear, and the power transformers are outfitted with dual windings to supply the new line up. It is now necessary to install the second line up to provide power to the areas of Niagara Falls experiencing significant growth.

Good Utility Practice (5.4.3.2.B.1.b)

Kalar Substation was originally built in with provisions for a second line up of switchgear. The substation has been operating since 2003 and has recently reached capacity. With new growth in South Niagara, it is necessary to install the second lineup of switchgear to expand the capacity of the substation.

Project Name: Kalar TS Switchgear
Category: System Access



The graph above shows the peak loading at Kalar TS. This load is serviced by two 45 MVA dual winding transformers. Only one winding from each transformer is connected (22.5 MVA) each. The bus has a capacity of 2000 A and the new Niagara South Hospital requires 15 MVA, so an additional bus is required.

Good utility practice is to load each transformer to no more than 50% of its capacity in order to provide redundancy. To achieve this, the new lineup of switchgear will be connected to the secondary windings of each power transformer.

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is high, this program ranked 6 out of 24 projects in our Project Priority Matrix for 2021. Compliance with the Distribution Service Code, adhering to our Conditions of Service and meeting the Ontario Energy Board's service quality requirements for customer requests is mandatory.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The project scope involves installing a new lineup of switchgear at Kalar TS. Kalar TS is currently at capacity, the new switchgear is necessary to provide power to the South Niagara Hospital and residential/commercial developments in South Niagara.

This solution is extremely efficient and cost effective as the majority of time and effort required to increase capacity has already been complete when the substation was first built. Power transformers are currently installed, energized and available to supply a new line up of switchgear. The physical space exists, so no additional buildings are necessary.

Project Name: Kalar TS Switchgear
Category: System Access

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)
Customers benefit by having their development supplied with a new, reliable and service built to current standards. Having more customers on the grid benefits existing customers by reducing distribution rate impacts.
Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)
The objective of the project is not to impact reliability and performance, it is to expand capacity at the substation to provide new customers with power. However, a brand new installation will be reliable and less prone to outages than existing equipment.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.3.2.B.1.d.iii)
Project Design Alternatives: A possible alternative would be to obtain additional breaker positions at other existing Hydro One stations. This would be a very costly short term solution and would not fully address constraint issues. Taking into consideration that Kalar was originally designed to have a second set of switchgear installed, the majority of the work to expand the system is already complete. Kalar TS has two power transformers with dual secondary windings. The second set of secondary windings are currently not connected, but are awaiting the new switchgear. The building is already constructed and in place, the physical space for the new switchgear exists, and cable trays were installed at time of construction for the new feeders. Since the substation was originally constructed to accommodate a second line up of switchgear, any project alternatives are not nearly as cost effective as adding the second line up of switchgear. Scheduling Alternatives: The work is scheduled to meet future load growth and alleviate existing capacity constraints. Delaying installation would impact NPEIs ability to service new customers. Ownership Alternatives: Not applicable.
Safety (5.4.3.2.B.2)
The switchgear line up is designed and constructed in accordance with NPEIs standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Prior to energization, all worked is inspected and signed off by NPEI.
Cyber-Security and Privacy (5.4.3.2.B.3)
This project involves modification of the communication network. Communication networks are susceptible to being intercepted by hackers if they are not adequately protected. Security measures are considered in both the software and hardware components of the devices and communication network utilized for this project.

Project Name: Kalar TS Switchgear
Category: System Access

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

There will be coordination between NPEI, NBM, the supplier of the switchgear, the installer and commissioning. There will also be coordination with Hydro One, IESO and potentially with customers (if outages are required).

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The new switchgear lineup will be installed with modern electronic relays which will facilitate future operational requirements as they arise.

Environmental Benefits (5.4.3.2.B.2.B.5)

Not applicable.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Category – Specific Requirements – System Access (5.4.4.2.C - SA)

Factors Affecting Timing/Priority (5.4.4.2.C – SA.i)

This project is very high priority, as other projects (South Niagara Feeders) depend on it. Future customers, the South Niagara Hospital and commercial and residential developers also depend on the expansion of this infrastructure. As far as timing, the supply of the switchgear itself is a factor.

NPEI is will be relying on third parties for the supply, installation and commissioning of the new switchgear. The availability of qualified installers may affect the timing as well as any issues encountered during commissioning.

Factors Related to Customer or Third-Party Preferences (5.4.4.2.C – SA.ii)

The project relates to equipment owned by NPEI on land owned by NPEI. Customer's preferences are to be supplied by a reliable source of power, and this project addresses those needs.

Factors Affecting the Final Cost of the Project (5.4.4.2.C – SA.iii)

Third party rates
NPEI will be relying on third parties to assist with the procurement, installation and commissioning of the switchgear. This process has already started and is on schedule. These costs have been estimated and budgeted but they still impact the final cost of the project.

Unforeseen issues during construction.
The original substation was designed to include a second line up of switchgear at a later date. The design of the new lineup is complete based on the existing design. It is always possible that during construction issues arise that affect the final cost of the project.

Project Name: Kalar TS Switchgear
Category: System Access

Measured used to Minimize Controllable Costs (5.4.4.2.C – SA.iv)

Supply, install and commissioning of the switchgear will be awarded through an RFP process. This process requires three bids and the bids to be evaluated by both NPEI internal staff and a contracted third party. Bids are evaluated to balance both costs and requirements of the project, ultimately looking for the best value.

Other Planning Objectives (5.4.4.2.C – SA.v)

The main planning objectives of the project are to ensure adequate electricity supply to South Niagara for now and the future. There are no additional planning objectives.

Other Project Design and/or Implementation Options Considered (5.4.4.2.C – SA.vi)

The substation was originally built with provisions for a second lineup of switchgear. It has now reached capacity, and with future development it is time to expand. In the short term, circuits can be shifted and offloaded, but there are no other long term project design options.

Summary of Result Analysis – "Least Cost", "Cost Efficient" Option (5.4.4.2.C – SA.vii)

As Kalar substation was originally built to accommodate this second line up of switchgear. The infrastructure and transformers are already in place to accommodate the new line up of switchgear.

With the development planned for South Niagara, adding the second line up of switchgear is both the "Least Cost" and most "Cost Efficient" option available.

Economic Evaluation Results (5.4.4.2.C – SA.viii)

Not applicable.

System Impacts, Related Costs, and Cost Recovery Methods (e.g. REG investment) (5.4.4.2.C – SA.ix)

There is no additional system impact (e.g. REG investment) associated with this project.

Project Sign-Off

Prepared By:	Weston Sagle	Authorized By:	
Date:	February 13 2020	Date:	
		Completion Date:	

Capital Project Summary

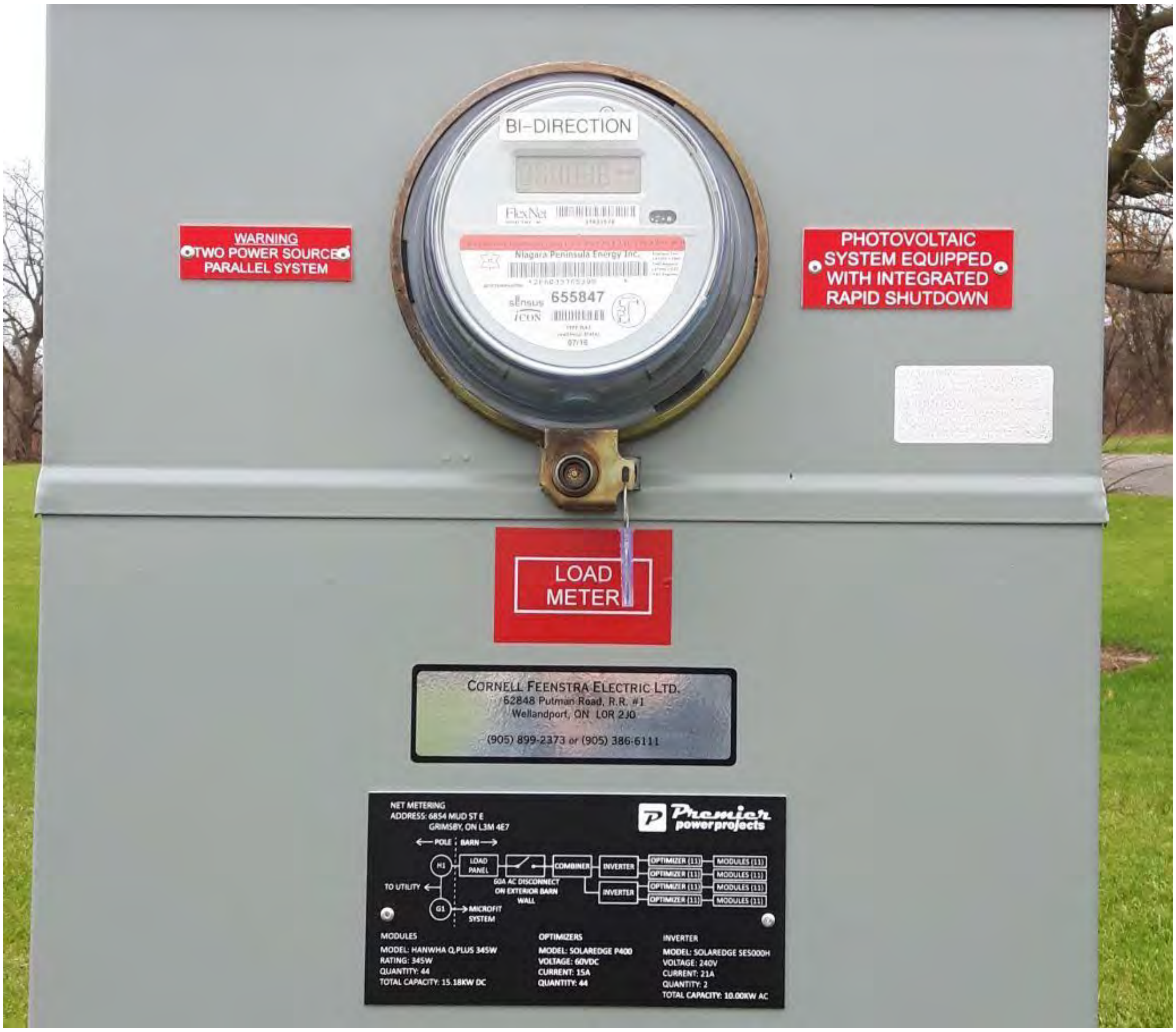
Project Name:	Metering - General	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Access	**Service Area:**	All

General Information on Project (5.4.3.2.A)

Project Summary	This capital program manages an allowance for the metering equipment to facilitate system access connections of new commercial and residential developments. Metering costs resulting from these new customer connection requirements fall under this budget allowance.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:** $405,050.00			
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** $0.00 **NPEI Estimated Cost:** $405,050.00			
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	TBD			
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 1, 2021 **In Service Date:** December 31, 2021			
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$100,000	$100,000	$100,000	$105,050

Project Name: Metering - General
Category: System Access

Images, Drawings, Maps, & Other Reference Material

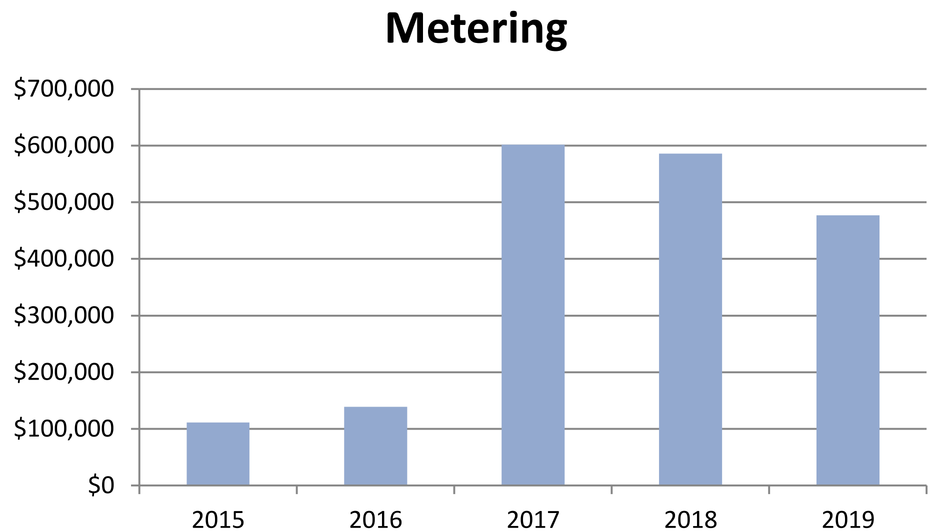


Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The largest schedule risk for this program is on time delivery of meters from the vendor. Risk mitigation is accomplished by ordering meters with sufficient lead time and maintaining inventory levels.

Project Name: Metering - General
Category: System Access

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)



Historical spending for metering shows a sharp increase in spending starting in 2017. Since 2017 spending has remained consistent.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not applicable.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

As a primary driver, NPEI is mandated to provide metering for new customers, replace failed units and eliminate meters that have a history of poor reliability. These requirements are part of the Distribution System Code (DSC), Conditions of Service and meeting of exceeding the Ontario Energy Board service quality requirements for customers requests.

Good Utility Practice (5.4.3.2.B.1.b)

The installation of meters is driven by customer demand and must be connected within a time line prescribed by the OEB. The smart meters installed help advance NPEIs grid modernization efforts by providing a variety of information at each service. This information is used to monitor outages, ensure safety by detecting reverse power flow and access voltage information.

Project Name: Metering - General
Category: System Access

Investment Priority (5.4.3.2.B.1.c)
On NPEI's Project Priority Matrix, the investment ranks high as compliance with the Distribution Service Code, adhering to our Conditions of Service and meeting the Ontario Energy Board's service quality requirements for customer requests is mandatory. Accurate electricity metering of power consumption per Measurement Canada's standards will be provided to all customers.
Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)
Installation smart meters increases efficiency as they can be read remotely. These devices also feed information into out outage management system allowing NPEI to identify and locate power outages in a timely manner. Smart meters provide large amount of data which will aid in grid modernization efforts.
Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)
Customers will be able to monitor their energy consumption and have access to real time outage information through NPEI's outage management system.
Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)
Installing new meters reduces the likelihood of failure due to age or condition. The data from the meters is also fed into our electrical system modeling software, providing real loading data which is crucial when designing new infrastructure and balancing our current system.
Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)
Project Design Alternatives: Not applicable. Scheduling Alternatives: Not applicable. Ownership Alternatives: Multi residential developments have the option of a bulk meter or individually metered units.
Safety (5.4.3.2.B.2)
All installations are completed in accordance with Ontario Regulation 22/04 to ensure no undue safety hazards.
Cyber-Security and Privacy (5.4.3.2.B.3)
All metering data is encrypted.
Co-ordination and Interoperability - **Co-ordination with utilities, regional planning and/or links with 3rd parties** (5.4.3.2.B.4.a)
The investment applied the requirements of Ontario Regulation 22/04 as overseen by the Electrical Safety Authority, who provide clearance prior to energization.
Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)
Not applicable.

Project Name: Metering - General
Category: System Access

Environmental Benefits (5.4.3.2.B.2.B.5)

Not applicable.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

The data provided by meters is crucial for customers participating in CDM programs. Utility grade meter data is necessary for IPMVP option C.

Category – Specific Requirements – System Access (5.4.4.2.C - SA)

Factors Affecting Timing/Priority (5.4.4.2.C – SA.i)

Meter installations are based on customer demand and requires NPEI to be responsive once a request has been made. Requests are prioritized and scheduled to ensure performance according to the Ontario Energy Board's Scorecard metric.

Factors Related to Customer or Third-Party Preferences (5.4.4.2.C – SA.ii)

The installation of meters is scheduled around the customer's needs.

Factors Affecting the Final Cost of the Project (5.4.4.2.C – SA.iii)

The cost of the project is impacted by material, labour, vehicle, mobilization and administration.

Measured used to Minimize Controllable Costs (5.4.4.2.C – SA.iv)

Costs are minimized through standardized equipment, design and bulk purchasing. A dedicated fleet is stocked with all the required tools and materials for meter work.

Other Planning Objectives (5.4.4.2.C – SA.v)

NPEI's planning objectives are considered on a case by case bases, as detailed in 5.4.2 of the Distribution Service Plan.

Other Project Design and/or Implementation Options Considered (5.4.4.2.C – SA.vi)

When multi residential projects are in the design phase, options for bulk metering, individual meters and in suite metering are discussed and explored.

Summary of Result Analysis – "Least Cost", "Cost Efficient" Option (5.4.4.2.C – SA.vii)

The options for multi residential projects are presented to the developer in the design stage. At this point it is up to the developer to choose which method of metering they prefer.

Economic Evaluation Results (5.4.4.2.C – SA.viii)

When a capital contribution is required, economic evaluations are performed in accordance with section 3.2 of the Distribution System Code and 2.1.2 of NPEI's Conditions of Service.

System Impacts, Related Costs, and Cost Recovery Methods (e.g. REG investment) (5.4.4.2.C – SA.ix)

Not applicable.

Project Name: Metering - General
Category: System Access

Project Sign-Off			
Prepared By:	Weston Sagle	Authorized By:	
Date:	January 24, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	Road Relocation	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Access	**Service Area:**	All

General Information on Project (5.4.3.2.A)

Project Summary	An allowance is maintained for the relocation/construction of distribution facilities to resolve conflicts with planned road works by such Governmental Agencies as the M.T.O., Regional Municipality of Niagara and the various Municipal Agencies within the Service territory. Additions and reinforcement to the distribution system resulting from new construction requests fall under this budget. Tracking is accomplished with individual Project Numbers assigned to the various projects as required within the Corporate Accounting System.
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:** $540,992.50
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** $167,711.25 **NPEI Estimated Cost:** $373,211.25
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	Not applicable.
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 1 2021 **In Service Date:** December 31 2021

	Q1	Q2	Q3	Q4
Estimated Expenditure Timing (5.4.3.2.A.iv)	$50,000	$100,000	$200,000	$190,992.50

Project Name: Road Relocation
Category: System Access

Images, Drawings, Maps, & Other Reference Material

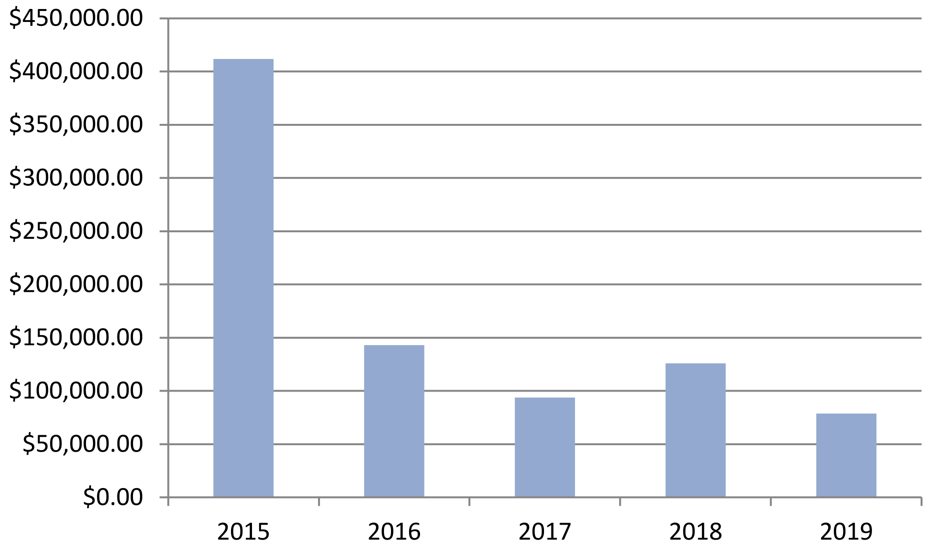
Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The schedule risk is primarily the timing of the municipality's roadway schedule. NPEI works closely with the Road Authority, which is either the City of Niagara Falls, the Niagara Region or the Ministry of Transportation. Despite ongoing communication, it is possible that priorities shift and project timelines change. All efforts are made to remain responsive to all RA work requests.

Project Name: Road Relocation
Category: System Access

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

The table below shows actual costs of Road Relocation projects from 2015 to 2019



Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not applicable.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver is MTO or municipal road works that requires the relocation of NPEI's infrastructure. All relocation project are initiated by municipalities or the MTO.

The secondary driver is NPEI's obligation as outlined in the Public Service Works on Highways Acts, which requires NPEI to work road authorities to relocate plant in order to maintain and improve public road infrastructure.

Good Utility Practice (5.4.3.2.B.1.b)

Plant relocation for road authority presents an opportunity to update dated infrastructure to current standards, which in turn addresses existing reliability and performance concerns. NPEI maintains opens lines of communication with the municipality and MTO to start design well in advance of construction.

Investment Priority (5.4.3.2.B.1.c)

Investment priority is high and ranks 6 out of 24 on NPEI's project priority matrix. NPEI is obligated to complete plant relocations per the Public Service Works on Highways Act. NPEI also does not have the option to defer these projects, so planning and coordination is vital to ensure access to appropriate resources and equipment.

Project Name: Road Relocation
Category: System Access

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)
For this type of project, do nothing is not a project alternative. NPEI is involved at the design stage of these projects and looks for opportunities to minimize relocation requirements which provides a cost savings for both parties. When relocation work is required, the opportunity to improve the existing system to create flexibility in operations and accommodate for potential future needs is explored.
Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)
Customers benefit from increased reliability due to new assets.
Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)
Although the purpose of these projects is not to increase reliability, depending on the age of the assets being relocated, it is positively impacted due to installation of new infrastructure based on current design standards.
Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)
Project Design Alternatives: The options are to replace like for like, or to upgrade for future considerations. Typically assets are replaced like for like as the road authority is responsible for 50% of the costs, but when there is an opportunity to address future concerns, it's advantageous from a cost perspective to address these needs at the time of relocation rather than returning at a late date to perform the work. Scheduling Alternatives: NPEI works closely with the municipality or MTO to accommodate schedule. Sometimes it is possible that relocations may be deferred until after the road work is complete, these decisions are evaluated objectively in conjunction with the road authority and third parties. Ownership Alternatives: NPEI is the owner of relocated assets.
Safety (5.4.3.2.B.2)
All work is completed in accordance with Ontario Regulation 22/04 to ensure no undue safety hazards. Often times relocation work contains end of life assets, providing a great opportunity to cost share the replacement of the assets, increasing the overall safety of the system.
Cyber-Security and Privacy (5.4.3.2.B.3)
Not applicable.
Co-ordination and Interoperability - **Co-ordination with utilities, regional planning and/or links with 3rd parties** (5.4.3.2.B.4.a)
Relocation involves coordination with the Region of Niagara, the City of Niagara Falls, the Ministry of Transportation, Bell Canada, Rogers, Cogeco, NRBN, Hydro One and other third parties and consultants. When needed, coordination with neighbouring LDCs such as Welland Hydro, CNP or Alectra may be necessary.

Project Name: Road Relocation
Category: System Access

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

Whenever plant is relocated NPEI uses the opportunity to consider modifications which facilitate future operational requirements.

Environmental Benefits (5.4.3.2.B.2.B.5)

Not applicable.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Category – Specific Requirements – System Access (5.4.3.2.C - SA)

Factors Affecting Timing/Priority (5.4.3.2.C – SA.i)

These projects are driven by external agencies, NPEI has very little control over factors affecting the timing and priority. NPEI works closely with these agencies to develop a schedule that works for all parties involved.

Factors Related to Customer or Third-Party Preferences (5.4.3.2.C – SA.ii)

The primary customer is the road authority, who provides input into the relocation design and ultimately approves the plans. NPEI's electricity customers have an opportunity for input as project letters are provided to customers in the area where the relocation work is being undertaken

Factors Affecting the Final Cost of the Project (5.4.3.2.C – SA.iii)

The cost of the project is impacted by material, labour, vehicle, mobilization and administration.

Measured used to Minimize Controllable Costs (5.4.3.2.C – SA.iv)

All relocation projects are completed in accordance with NPEI's standards which have been developed to minimize overall costs and impact on customers.

Other Planning Objectives (5.4.3.2.C – SA.v)

NPEI's planning objectives are considered on a case by case bases, as detailed in 5.4.2 of the Distribution Service Plan.

Other Project Design and/or Implementation Options Considered (5.4.3.2.C – SA.vi)

When the project is in the design phase, all feasible options are considered, from adjusting the curb and sidewalk alignment to having road authority contractors perform relocation work.

Summary of Result Analysis – "Least Cost", "Cost Efficient" Option (5.4.3.2.C – SA.vii)

Options are not evaluated until project specifics are known.

Economic Evaluation Results (5.4.3.2.C – SA.viii)

Not applicable.

Project Name: Road Relocation
Category: System Access

System Impacts, Related Costs, and Cost Recovery Methods (e.g. REG investment) (5.4.3.2.C – SA.ix)
Not applicable.

Project Sign-Off			
Prepared By:	Weston Sagle	Authorized By:	
Date:	January 24, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	South Niagara Feeders Phase 1	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Access	**Service Area:**	Niagara Falls

General Information on Project (5.4.4.2.A)

Project Summary	A new hospital is currently in design and scheduled to complete construction in 2026. Niagara Health approached NPEI to service to the service the new load (approx 15 MVA). The hospital requires two circuits as per the Ministry of Health standard. Along with the hospital, plans have been submitted for new residential and commercial in the area. The current infrastructure is not able to meet the demands of future growth. In order to meet the demands, two new 13.8 kV circuits will be run from Kalar substation to South Niagara. The project is split into 3 phases.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$1,603,149.10		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	TBD		
	NPEI Estimated Cost:	$1,603,149.10		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	Hospital (15 MVA)			
Project Dates (5.4.3.2.A.iv)	**Start Date:**	January 1, 2021		
	In Service Date:	December 31, 2021		
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$100,000	$400,000	$600,000	$503,149.10

Project Name: South Niagara Feeders Phase 1
Category: System Access

Images, Drawings, Maps, & Other Reference Material

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The schedule risk for this program lies with the developer and the availability of NPEI's internal resources to design and service the development. The workload is driven by customer demand, which is not steady throughout the year. Another risk to schedule is long lead items such as large transformers and switchgear. This project is contingent on new switchgear being installed at Kalar Substation.

Obtaining easements on private property, hydro one right of way, crossing the Welland River are a few issues to be resolved that may impact schedule.

To mitigate risks, NPEI works closely with developers and third parties to ensure a timely service connection. This involves reviewing notices for zoning by-law amendments and reaching out to potential developers. At this time the process is communicated with the developer and time lines are established.

Project Name: South Niagara Feeders Phase 1
Category: System Access

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

In 2018, a similar project was completed in the Lincoln area of Victoria Avenue north of Eighth Avenue. This project was a rebuild and installation of additional circuit along 2km of the system. The total cost was $807,268.73 (approx. $403,634.37 per km).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not applicable.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver for this project is customer demand.

When a commercial customer plans to upgrade or develop, they apply to NPEI to provide them with an electrical service. Per the Distribution System Code and Conditions of Service, NPEI is required to provide the customer with an Offer to Connect.

In this case, NPEI has been approached by Niagara Health to supply power to a new hospital in South Niagara. The total power requirement is 15 MVA with redundant circuits.

Good Utility Practice (5.4.3.2.B.1.b)

Expansions and reinforcement to the distribution system are the result of customer demand. These customers must be supplied within a time line prescribed by the OEB. When large customers are connected to NPEI's grid, the infrastructure is designed in house. NPEI leverages senior staff's years of experience to ensure the distribution system remains resilient and addresses existing reliability and performance concerns.

As part of our standard engineering practices, pole lines are designed and built to meet or exceed the latest revision of CSA C22.3 No.1. Overhead Systems, which ensures that new distribution system expansions, extensions and replacement are constructed to a level appropriate with the regional climate.

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is high, this program ranked 7 out of 24 projects in NPEI's Project Priority Matrix for 2021. Compliance with the Distribution Service Code, adhering to our Conditions of Service and meeting the Ontario Energy Board's service quality requirements for customer requests is mandatory.

Project Name: South Niagara Feeders Phase 1
Category: System Access

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The project scope is to construct a new pole line with two new 13.8 kV feeders to the new South Niagara Hospital. The new pole line will be built to accommodate future growth. The height of the poles will allow additional circuits to be added at a future date. The pole line design will incorporate stress loading of these additional circuits to ensure the poles can withstand the extra forces.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Customers benefit by having their development supplied with a new, reliable and service built to current standards. Having more customers on the grid benefits existing customers by reducing distribution rate impacts.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

The hospital is being supplied by two feeders. This has a large impact on both frequency and duration of outages as each feeder will have the capacity to supply the entire hospital. If one feeder goes down, the secondary feeder can supply the entire load, eliminating many outages.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Feeders from Murray TS
Supplying the new hospital from Murray TS was considered, but the station does not have sufficient capacity on any existing feeder. Obtaining a spare feeder from Hydro One was considered, but difficult to coordinate as Hydro One is currently redesigning Murray. This options is also cost prohibitive as the budget cost provided by Hydro One for a new feeder is approximately 1 million. There was also difficulties crossing the QEW due to MTO bridge work.

Scheduling Alternatives:

This project is customer driven and does not have alternative scheduling options with the exception of minor variation in timing of the service connection. Niagara Health approached NPEI 7 years in advance of opening to ensure that NPEI is able to accommodate.

Ownership Alternatives:

The new pole line will consist solely of NPEI assets on the public right of way. As this is a large load customer, they will be primary metered and own their own substation, i.e. switchgear, transformers.

Safety (5.4.3.2.B.2)

All new commercial and industrial services are installed in accordance with NPEI's standards and meet the requirements of Ontario Regulation 22/04. As the customer will own their own substation, an operating agreement which will include, provisions for safe operation of equipment.

Larger commercial customers are typically provided with an underground service. This reduces the likelihood of energized wires coming in contact with trees, animals and objects as well as pole structures failing and causing injury or property damage.

Project Name: South Niagara Feeders Phase 1
Category: System Access

Cyber-Security and Privacy (5.4.3.2.B.3)

Not applicable.

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This project will be coordinated with the City of Niagara Falls, the Niagara Region, Bell Canada, Enbridge Gas, applicable road authority, Hydro One, Rogers, Cogeco and NRBN and potentially private property owners for easements.

As this is a large project, NPEI has already met with Niagara Health and some of the parties mentioned above in regards to utility coordination. It is expected more meetings will occur on an a regular basis. During the design phase NPEI hosts meetings with developers and third parties to address issues as they arise.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

These two new circuits will be connected to an existing circuit (with an open point) at the corner of Montrose and Biggar. This allows greater flexibility in contingency scenarios.

Environmental Benefits (5.4.3.2.B.2.B.5)

Not applicable.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

NPEI connects new developers with our CDM department at the design phase to help incorporate efficiency into the building design.

Category – Specific Requirements – System Access (5.4.4.2.C - SA)

Factors Affecting Timing/Priority (5.4.4.2.C – SA.i)

Kalar Switchgear installation
The two new feeders will be supplied from Kalar substation. Currently Kalar has one lineup of switchgear which is fully occupied, but was designed to accommodate another line up. A separate project is to install this line up of switchgear. Without this line up of switchgear, there is no capacity to supply the South Niagara Hospital. Any delays experienced with the Kalar Switchgear installation would impact this project.

Coordination with 3rd parties
NPEI coordinates the design and construction with gas, water and communication companies. The routing of the new pole line has not been finalized, and the final routing will be impacted largely by third parties. NPEI may have to use a Hydro One corridor or obtain easements on private property. These options will be explored during the design phase to choose the most cost-effective and efficient routing.

Availability of Labour and Materials
NPEI utilizes both internal resources and contractors to construct electrical infrastructure for new customers. For large projects, material acquisition can consume a significant portion of the schedule.

Project Name: South Niagara Feeders Phase 1
Category: System Access

Developer's Schedule
Ultimately the work is based around the proposed schedule of the development which is beyond NPEI's control.

Factors Related to Customer or Third-Party Preferences (5.4.4.2.C – SA.ii)

The electrical plant for large commercial in constructed in direct response to customer needs. NPEI is responsible for the system design and connection. For large commercial, each site has its own specific requirements, like the service size, transformer type and ownership, servicing location and in this case a redundant circuit. NPEI works together with the developer to ensure the best interest of the customer.

Factors Affecting the Final Cost of the Project (5.4.4.2.C – SA.iii)

A factor affecting the final cost of the project is the routing of the new circuits. There are several road crossing and a river crossing. The recoverable cost will also impact the final cost. It is estimated based on the forecast load, but actual loading ends up being used.

Measured used to Minimize Controllable Costs (5.4.4.2.C – SA.iv)

Controllable costs are minimized through the use of standard materials, standardized designs and bulk purchasing when possible.

Other Planning Objectives (5.4.4.2.C – SA.v)

The new pole line will be built with poles that are capable of handling additional circuits. With the hospital being built South of Niagara, it is expected that other development will take place in the surrounding area. NPEI has already been approached by a developer for a 2000 home subdivision. Servicing these customers in the future will be simple with poles already in place to accommodate a new circuit.

Other Project Design and/or Implementation Options Considered (5.4.4.2.C – SA.vi)

Supplying the new hospital from Murray TS was considered, but the station does not have sufficient capacity on any existing feeder. Obtaining a spare feeder from Hydro One was considered, but difficult to coordinate as Hydro One is currently redesigning Murray. This options is also cost prohibitive as the budget cost provided by Hydro One for a new feeder is approximately 1 million. There was also difficulties crossing the QEW due to MTO bridge work.

There is a separate project to install a new line up of swtichgear at Kalar and these circuits will be fed from the new switchgear. The routing of the new circuits is yet to be determined.

Summary of Result Analysis – “Least Cost”, “Cost Efficient” Option (5.4.4.2.C – SA.vii)

The final routing of the new circuits has yet to be finalized. In determining the routing, many options will considered such as road crossings, water crossing, obtaining property and/or easements, total distance, etc.

Project Name: South Niagara Feeders Phase 1
Category: System Access

Economic Evaluation Results (5.4.4.2.C – SA.viii)

Connection costs are chargeable to the developer. NPEI conducts economic evaluations on commercial and industrial developments in accordance with Section 3.2 of the Distribution Code if expansion work is required. The results of the evaluations vary and have not been calculated as of yet.

System Impacts, Related Costs, and Cost Recovery Methods (e.g. REG investment) (5.4.4.2.C – SA.ix)

There is no additional system impact (e.g. REG investment) associated with this project.

Project Sign-Off

Prepared By:	Weston Sagle	Authorized By:	
Date:	February 3, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	Subdivision Lots / Connections	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Access	**Service Area:**	All

General Information on Project (5.4.4.2.A)

Project Summary	This Capital Program manages the installation and connection of new residential services within new and on-going residential developments such as subdivisions.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:** **Total:**	$417,970.00 $482,954.30 $900,924.30	Lots Connections	
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** **NPEI Estimated Cost:**	$425,342.00 $475582.30		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	TBD			
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 1 2021 **In Service Date:** December 31 2021			
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$150,000	$300,000	$300,000	$150,924.30

Images, Drawings, Maps, & Other Reference Material

Project Name: Subdivision Lots
Category: System Access

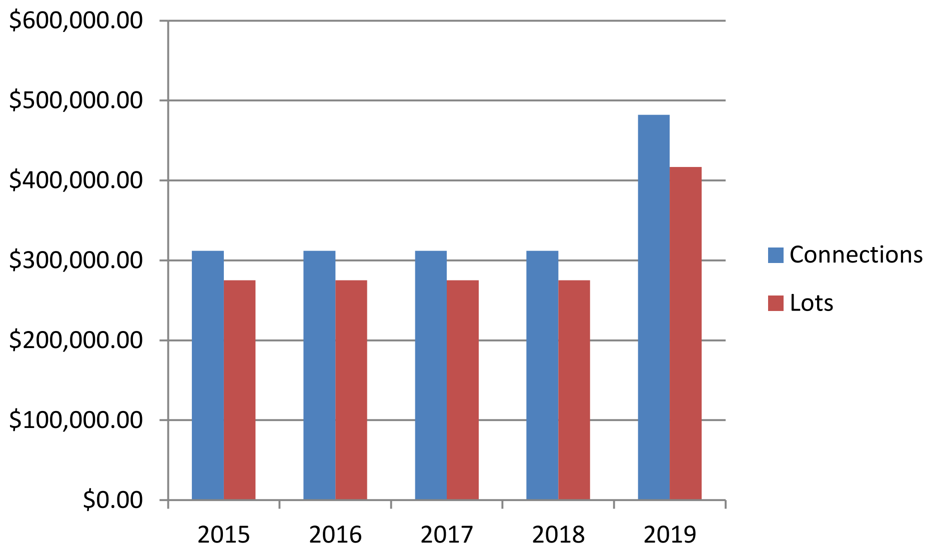
Project Name: Subdivision Lots
Category: System Access

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

Scheduled risks is primarily the timing of the developer's sites for servicing and the availability of resources to perform the work. The development of subdivisions doesn't occur evenly throughout the year. NPEI works closely with developers to establish timelines and ensure adequate resources are available to service lots. Materials required are standardized and stocked to ensure availability.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

Previous years budgets for subdivision lots and connections can be seen in the table below.



Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not applicable.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary investment driver is customer demand. Developers apply to NPEI to provide electrical infrastructure and connections. Per the Distribution System Code and Conditions of Service, NPEI is required to provide the connect new customers.

Good Utility Practice (5.4.3.2.B.1.b)

All underground residential services are designed to be resilient and adapt to future challenges. New subdivisions are all serviced underground, which is more resilient in adverse weather conditions (potentially caused by climate change) than an overhead system. New residences are provided with a 200 A service standard, which provides capacity for electrical vehicle charging.

Project Name: Subdivision Lots
Category: System Access

Investment Priority (5.4.3.2.B.1.c)
On NPEI's Project Priority Matrix, the investment ranks high (2 & 4 out of 24) as compliance with the Distribution Service Code, adhering to our Conditions of Service and meeting the Ontario Energy Board's service quality requirements for customer requests is mandatory.
Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)
The program funding is based on actual connection costs. Typically the investment does not impact system operation efficiency.
Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)
Customers benefit by having their development supplied with a new, reliable and service built to current standards. Having more customers on the grid benefits existing customers by reducing distribution rate impacts.
Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)
Reliability for new customers will be the same or better since the equipment is new and probability of failure is low. Also, an underground distribution network is not impacted by weather related events, so frequency of outages is reduced.
Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)
Project Design Alternatives: NPEI completes the system design and connection based around the developer's requirements as well as NPEI's standards and Conditions of Service. The options for design alternatives are limited as new subdivision design is highly standardized. Small changes, such as cable routing, can be made to accommodate. Scheduling Alternatives: The schedule is established by the developer with feedback from NPEI. Ownership Alternatives: Not applicable.
Safety (5.4.3.2.B.2)
All residential services are installed in accordance with NPEI's standards and meet the requirements of Ontario Regulation 22/04 Residential developments are provided an underground service. This reduces the likelihood of energized wires coming in contact with trees, animals and objects as well as pole structures failing and causing injury or property damage.
Cyber-Security and Privacy (5.4.3.2.B.3)
When new customers set up accounts, all customer information is handled in accordance with established privacy policies and guidelines.

Project Name: Subdivision Lots
Category: System Access

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This program is coordinated with the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln, the Town of Pelham, the Niagara Region, Bell Canada, Rogers, Cogeco and NRBN.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

New residential subdivisions are designed with capacity and capability to permit behind the meter generation and electric vehicle charging. Each service to a new residential building is sized for 200 A to facilitate customer load growth.

Environmental Benefits (5.4.3.2.B.2.B.5)

Not applicable.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Category – Specific Requirements – System Access (5.4.4.2.C - SA)

Factors Affecting Timing/Priority (5.4.4.2.C – SA.i)

Developer's schedule - Ultimately the work is based around the proposed schedule of the development which is beyond NPEI's control.

Coordination with third parties - NPEI coordinates subdivision design and construction with gas, water and communication companies. The availability of design information and resources from third parties may impact the timing of the project.

Availability of labour - NPEI utilizes both internal resources and contractors to construct electrical infrastructure for new customers.

Unplanned events - System Access projects rank highest in priority, however in the event of major unplanned outages resources will be allocated appropriately. I there is a higher than usual amount of major events, there is potential for delay.

Factors Related to Customer or Third-Party Preferences (5.4.4.2.C – SA.ii)

Electrical infrastructure for subdivisions is constructed in direct response to the customer needs via developer request for servicing of new homes.

Factors Affecting the Final Cost of the Project (5.4.4.2.C – SA.iii)

The final cost may be affected by the scope of work, type of subdivision (single-family vs townhouse), lot size and frontage, access to existing distribution infrastructure and road crossings requiring a concrete duct bank.

Measured used to Minimize Controllable Costs (5.4.4.2.C – SA.iv)

Controllable costs are minimized through the use of standard procedures, materials and design.

Project Name: Subdivision Lots
Category: System Access

Other Planning Objectives (5.4.4.2.C – SA.v)
When designing the electrical distribution system for residential subdivisions, NPEI takes other planning objectives into consideration such as future load growth and future electricity use (e.g. electric vehicle charging)
Other Project Design and/or Implementation Options Considered (5.4.4.2.C – SA.vi)
Not applicable.
Summary of Result Analysis – "Least Cost", "Cost Efficient" Option (5.4.4.2.C – SA.vii)
Not applicable.
Economic Evaluation Results (5.4.4.2.C – SA.viii)
NPEI conducts an economic evaluation of residential services in accordance with section 3.2 of the Distribution System Code and section 2.1.2 of NPEI's Conditions of Service. The developer is responsible for all costs up front, with the difference between the economic evaluation and actual costs being rebated upon lot connection over a 5 year period.
System Impacts, Related Costs, and Cost Recovery Methods (e.g. REG investment) (5.4.4.2.C – SA.ix)
There is no additional system impact (e.g. REG investment) associated with residential subdivision servicing.

Project Sign-Off

Prepared By:	Weston Sagle	Authorized By:	
Date:	January 29, 2020	Date:	
		Completion Date:	

Capital Project Summary

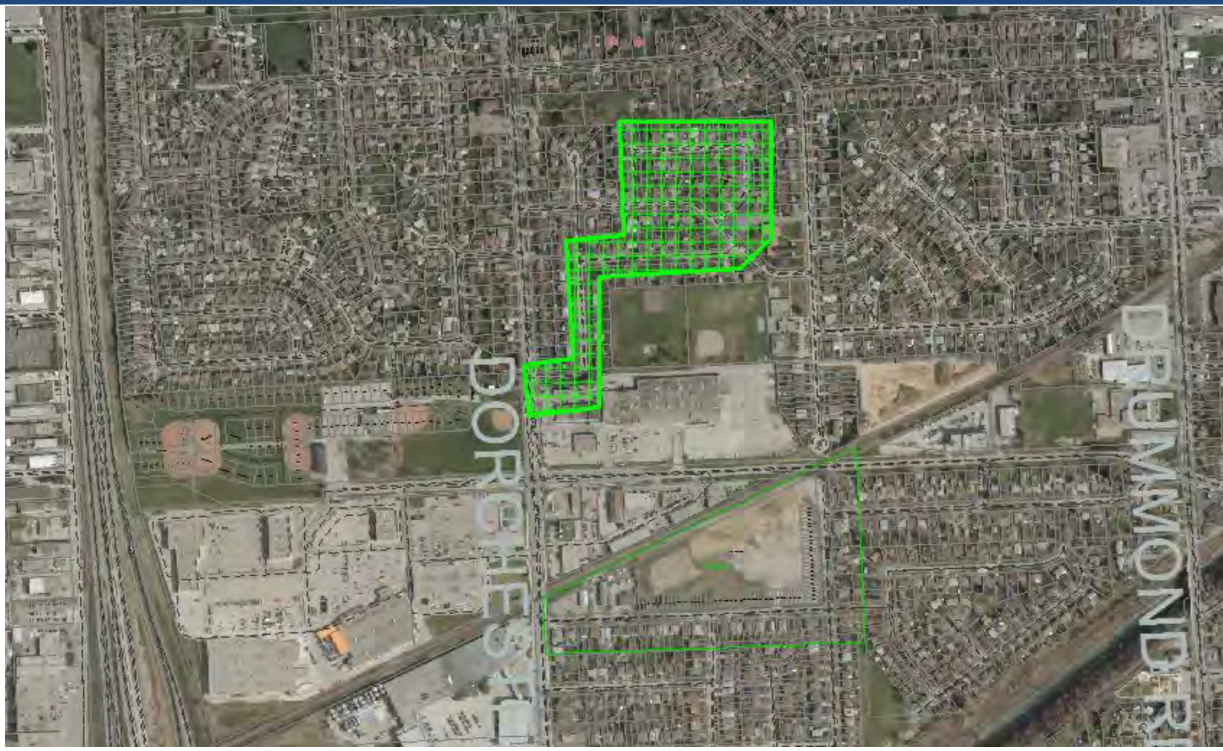
Project Name:	Cherryhill Drive Voltage Conversion	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	Niagara Falls

General Information on Project (5.4.4.2.A)

Project Summary	Project involves the replacement of 1.1 km of urban overhead single phase 2.4 kV circuit (built in 1962) with a single phase 8 kV primary line using 31 new 40' wood poles. The new pole line will be constructed in the same alignment as the existing.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$433,341.86		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	$0.00		
	NPEI Estimated Cost:	$433,341.86		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	87 customers / 261 kVA (assuming 3 kVA per customer)			
Project Dates (5.4.3.2.A.iv)	**Start Date:**	May 1, 2021		
	In Service Date:	November 30, 2021		
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	$30,000	$303,341.86	$100,000

Project Name: Cherryhill Drive Voltage Conversion
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material



Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints, approvals from applicable authorities and coordination with third parties. Risk mitigation is accomplished by completing the design 4-6 months in advance of construction and project scheduling in conjunction with Operations and Stores, coordinating with the road authority and third parties through the Public Utilities Coordinating Committee (PUCC).

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

In 2019, a similar project was completed in the Niagara Falls area of McLeod Road and Drummond Road. This project was Phase 3 of a multi-phase system rebuild/voltage conversion and included replacement of 76 poles and 250 customers. The total cost this phase was $828,037.52 (approx. $10,895.23 per pole and $3,312.15 per customer).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Project Name: Cherryhill Drive Voltage Conversion
Category: System Renewal

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver of this project is the age and condition of the existing pole line. The condition and age of the affected poles and transformers is summarized in the tables below.

Poles						
Age	0 - 10	11 - 20	21 - 30	31 - 40	41-50	> 50
Condition	Quantity					
Very Good	2	1	-	2	3	12
Good	-	-	-	-	5	1
Fair	-	-	-	-	-	5
Poor	-	-	-	-	-	2
Very Poor	-	-	-	-	-	-

Transformers					
Age	0 - 10	11 - 20	21 - 30	31 - 40	> 40
Condition	Quantity				
Very Good	-	-	-	-	-
Good	-	-	1	-	-
Fair	-	-	-	2	-
Poor	-	-	-	1	2
Very Poor	-	-	-	-	2

This subdivision is a mix of wood and concrete poles. The typical useful life of a fully dressed wood and concrete pole is 50 and 60 years respectively. The majority (60%) of poles are over 50 years old. The typical useful life of a transformer is 40 years, 45% of the existing transformers are over 40 years old.

The secondary driver is voltage conversion. The existing line is single phase 2.4 kV, the new line will be single phase 8 kV. Standardizing the voltage across the city offers tremendous benefit in terms equipment standardization, lower system losses, increased clearances and overall safety

Good Utility Practice (5.4.3.2.B.1.b)

The project was selected by historical knowledge and expertise of our system, which was verified by overlaying the health index of our assets in to our GIS system. With this information a heat map was generated giving a visual representation of areas requiring attention in our system.

As part of NPEI's standard engineering practices, pole lines are designed to meet or exceed the latest revision of CSA C22.3 No.1. Overhead Systems, which ensures new distribution system expansions, extensions and replacement are constructed to a level appropriate with the regional climate.

Project Name: Cherryhill Drive Voltage Conversion
Category: System Renewal

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is medium, this program ranked 10 out of 24 projects on NPEI's Project Priority Matrix for 2021. NPEI views System Renewal projects as a lower priority than System Access projects, unless the condition of the assets poses an immediately risk to system stability and/or public safety. Within System Renewal projects this projects ranks as medium priority as it has been deferred from previous years.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Planned replacement of assets compared to replacement at failure offers several advantages. The cost per pole is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums. Proactive replacement allows the entire line to be redesigned and in this case a voltage conversion.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line customers will experience improved reliability, the voltage conversion will provide greater flexibility and improve restoration times during outages. The risks associated with downed power lines will be drastically reduced with the installation of new poles, wires and associated hardware.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Rebuilding the pole line will greatly increase reliability as many of the assets are near or at end of life. The voltage conversion will reduce overall system losses and decrease frequency and duration of outages due to equipment failure.

The subdivision is currently supplied by two 13.8 kV / 4.16 kV step down transformers on the 12M32 circuit. The voltage conversion will allow for additional ties to the 12M32 which will provide greater flexibility and improve restoration times during outages.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Replace end of life assets
This option would replace only the assets identified as end of life. Voltage conversion would be a lost opportunity meaning system losses would not be reduced and system stability would not be increased. The work would be done piece by piece which would require ongoing maintenance to address issues with aging assets as they arise.

Replace assets upon failure
The only advantage to this option is up front cost savings which pales in comparison to the disadvantages. Overall total costs would be significantly higher as assets would be replaced on an emergency basis. Total quantity of outages would increase due to equipment failures and public safety would be put at risk. Voltage conversion opportunity would be lost.

Project Name: Cherryhill Drive Voltage Conversion
Category: System Renewal

Scheduling Alternatives:

In the event an unplanned job arises with a higher priority, the schedule can be revised to accommodate. However, as end of life asset replacement is deferred, there is an increased risk to public safety and system reliability decreases.

Ownership Alternatives:

None. This project consists of NPEI assets and is constructed on the public right of way.

Safety (5.4.3.2.B.2)

The pole line rebuild is designed and constructed in accordance with NPEIs standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Prior to energization, all worked is inspected and signed off by NPEI.

Replacement of deteriorated poles, wires and vintage transformers drastically reduces the likelihood of catastrophic failure, resulting in possible downed wires. Downed wires pose the greatest risk to public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3)

Not applicable.

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This project will be coordinated with the City of Niagara Falls, Bell Canada, Rogers and NRBN and road authority, where applicable.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

Not applicable.

Environmental Benefits (5.4.3.2.B.2.B.5)

Voltage conversion reduces system losses, ultimately requiring fewer resources. Depending on the current supply mix, this is beneficial for the environment.

Many of the poles to be replaced were treated with pentachlorophenol, although a great preservative PCP is classified as a probable human carcinogen. Removing and replacing these poles will ensure that no more pentachlorophenol leeches into the soil and ultimately our water supply.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Project Name: Cherryhill Drive Voltage Conversion
Category: System Renewal

Category – Specific Requirements – System Renewal (5.4.4.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.4.2.C – SR.i.a)

The proposed project aims to target assets proactively whose condition has deteriorated to the extent that prudent measures must be taken to safeguard the performance of the system and public welfare

Operational Effectiveness - SAIDI and SAIFI will be improved by proactively replacing poles and transformers before failure occurs
Safety - Replacing end of life poles avoids safety issues such as live wire down due to pole failure.
Customer Focus - Replacing poles and transformers, as well as voltage conversion, reduces the likelihood of long duration unplanned outages due to equipment failure.

In structuring the pole replacement strategy for 2021, NPEI reviewed the prioritized list of pole integrity deficiencies resulting from cyclical inspections. Areas with a high concentration of pole deficiencies are identified as targets for wholesale system renewal rather than individual change-outs. The decision to perform a wholesale rebuild is deemed to be more efficient when the area encompasses distribution transformers also at or near end of life and where system capacity and loss reduction benefits can also be realized. The balance of prioritized poles is scheduled for change out under the recurring project for pole replacements.

Asset Condition Relative to Typical Life Cycle (5.4.4.2.C – SR.i.b)

This subdivision is a mix of wood and concrete poles with pole mounted transformers. The typical useful life of a fully dressed wood and concrete pole is 50 and 60 years respectively. The majority (60%) of poles are over 50 years old. The typical useful life of a transformer is 40 years, 45% of the existing transformers are over 40 years old. The majority of the assets (poles and transformers) have reached their typical useful life.

Number of Impacted Customers (5.4.4.2.C – SR.i.c)

Residential: 87

Quantitative Customer Impact and Risk (5.4.4.2.C – SR.i.d)

As the assets age and risk of failure increases, frequency of interruptions will increase. Duration of interruptions will also increase depending on what time of day the failure occurs.

Although 87 customers are serviced directly by these assets, in the event of an outage it is possible that the feeder breaker for 12M32 opens which would impact 1758 customers.

Qualitative Customer Impact and Risk (5.4.4.2.C – SR.i.e)

As the assets continue to age beyond their life expectancy, outage frequency and duration becomes an increasingly large risk.

Value of Customer Impact (5.4.4.2.C – SR.i.f)

Value of customer impact is low. A failure would impact 87 residential customers for the duration of the outage. However, if the failure caused the feeder breaker to open, 1758 customers would be affected.

Project Name: Cherryhill Drive Voltage Conversion
Category: System Renewal

Factors Affecting Project Timing (5.4.4.2.C – SR.ii)

The project timing could be impacted by having to re-deploy resources to adjust for unexpected changes in customer demand, such as Road Authority work, subdivision development and commercial connections.

Effect on System O&M Costs (5.4.4.2.C – SR.iii)

The investment to rebuild Cherryhill will improve the reliability of electrical supply by reducing the frequency and duration of electrical outages, caused by aging equipment. This will effectively reduce the O&M costs associated with those outages.

As NPEI continues to convert remaining 4 kV infrastructure to 13.8 kV, O&M savings are realized through reduction carrying costs of materials and furnishing of spare parts.

Impact on Reliability and Safety (5.4.4.2.C – SR.iv)

The new pole line is built to current standards, resulting in greater clearances and better safety. Also, replacing end of life assets increases reliability and avoids safety issues due to failing poles and transformers.

The area surrounding the project has already been converted to 13.8 kV, leaving these remaining 87 customers serviced by 2 step down transformers. Performing a voltage conversion allows for the elimination of these two critical transformers, ultimately increasing reliability for these customers.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.4.2.C – SR.v)

Alternatives have been discussed in section (5.4.3.2.B.1.d.iii). As demonstrated by NPEIs asset condition assessment, this section of line is at the point of needing a rebuild. There are also other areas of NPEIs service territory that are in similar condition and due for a rebuild. The benefits of the rebuild are clear - the voltage conversion increases reliability, building to new standards increases clearances and safety, replacing end of life equipment also increases safety and reliability.

Rebuilding the pole line will avoid and/or reduce power outages. Maintaining the status quo will result in future outages which will lead to unplanned work and customer dissatisfaction.

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.4.2.C – SR.vi)

Replacing the existing infrastructure like for like is a wasted opportunity. The area of this project is surrounded by 13.8 kV, and special provisions are in place to service this area. Eliminating the 4 kV infrastructure is a secondary driver of this project and if not done during this rebuild, it will be done at some time in the future at a much higher overall cost.

Project Sign-Off

Prepared By:	Weston Sagle	Authorized By:	
Date:	January 23, 2020	Date:	
		Completion Date:	

Capital Project Summary

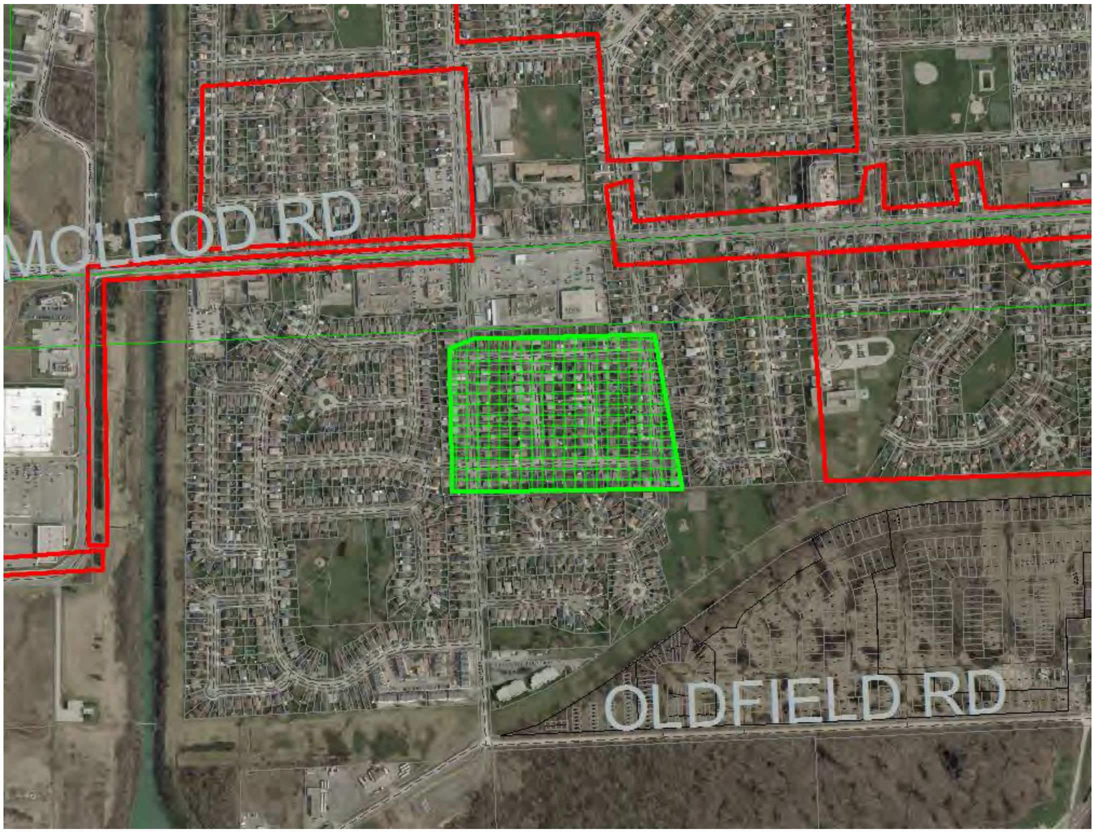
Project Name:	Cooper, Jill, Jordan & Marie Claude Area - Rebuild	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	Niagara Falls

General Information on Project (5.4.3.2.A)

Project Summary	Project scope involves the rebuild of an overhead supplied subdivision (built in the 1960s). Rebuild in place using tree wire and 40' poles. Replacement of two end of life transformers and reuse of remaining transformers. This project includes the following streets Cooper Dr, Jordan Ave, MarieClaude Ave, Fern Ave and Jill Dr. The project also includes replacement of existing open secondary bus. Benefits include reduced system losses, improved equipment clearances, reinforcement and capacity increase of the supply in the area			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$374,855.88		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	$0.00		
	NPEI Estimated Cost:	$374,855.88		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	98 customers / 294 kVA (assuming 3 kVA per customer)			
Project Dates (5.4.3.2.A.iv)	**Start Date:**	April 1, 2021		
	In Service Date:	November 30, 2021		
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	0	$100,000	$100,000	$274,855.88

Project Name: Cooper, Jill, Jordan & Marie Claude Area - Rebuild
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material



Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints, approvals from applicable authorities and coordination with third parties. Risk mitigation is accomplished by completing the design 4-6 months in advance of construction and project scheduling in conjunction with Operations and Stores, coordinating with the road authority and third parties through the Public Utilities Coordinating Committee (PUCC).

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

In 2019, a similar project was completed in the Niagara Falls area of McLeod Road and Drummond Road. This project was Phase 3 of a multi-phase system rebuild/voltage conversion and included replacement of 76 poles and 250 customers. The total cost this phase was $828,037.52 (approx. $10,895.23 per pole and $3,312.15 per customer).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Project Name: Cooper, Jill, Jordan & Marie Claude Area - Rebuild
Category: System Renewal

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver is the condition and age of the existing poles and transformers.

The secondary driver is outages due to animal and tree contact. This is an older neighbourhood with mature trees and has experienced several outages due to overgrown vegetation and animal contact. Currently the primary conductor is bare and the secondary conductors are open. The new construction will utilize tree wire for primary conductors and spun bus secondary.

Poles						
Age	0 - 10	11 - 20	21 - 30	31 - 40	41-50	> 50
Condition	Quantity					
Very Good	4	1	4	3	-	-
Good	-	-	-	-	1	1
Fair	-	-	-	-	-	19
Poor	-	-	-	-	-	1
Very Poor	-	-	-	-	-	1

Transformers					
Age	0 - 10	11 - 20	21 - 30	31 - 40	> 40
Condition	Quantity				
Very Good	3	2	-	-	-
Good	-	-	1	-	-
Fair	-	-	1	-	-
Poor	-	-	-	-	-
Very Poor	-	-	-	-	2

This subdivision is comprised of wood poles. The typical useful life of a fully dressed wood pole is 50 years. The majority (60%) of poles are over 50 years old. The typical useful life of a transformer is 40 years, two of the existing transformers are older than 40 years and will be replaces while the rest will be re-used.

Project Name: Cooper, Jill, Jordan & Marie Claude Area - Rebuild
Category: System Renewal

Good Utility Practice (5.4.3.2.B.1.b)

The project was selected by historical knowledge and expertise of our system, which was verified by overlaying the health index of our assets in to our GIS system. With this information a heat map was generated giving a visual representation of areas requiring attention in our system.

As part of our standard engineering practices, pole lines are designed and built to meet or exceed the latest revision of CSA C22.3 No.1. Overhead Systems, which ensures that new distribution system expansions, extensions and replacement are constructed to a level appropriate with the regional climate.

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is Low. NPEI views System Renewal projects as a lower priority than System Access projects, unless the condition of the assets poses an immediately risk to system stability and/or public safety. Within System Renewal projects this projects ranks as medium priority as it has been deferred from previous years.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Planned replacement of assets compared to replacement at failure offers several advantages. The cost per pole is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums. Proactive replacement allows the entire line to be redesigned.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line customers will experience improved reliability. Using tree wire for primary and spun bus secondary will help to reduce outages due to tree and animal contact. A new pole line with spun bus is more aesthetically pleasing than open bus.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By rebuilding the pole line customers will experience improved reliability. Using tree wire for primary and spun bus secondary will help to reduce outages due to tree and animal contact. The risks associated with downed power lines will be reduced with the installation of new poles, wires and associated hardware.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Replace poles and transformers as they fail
Replacing assets as they fail ends up costing more overall as work needs to be completed on an emergency basis. This also leads to a higher number of outages which are longer in duration. The customers are left with a mix of new and old infrastructure that is no more reliable than the existing.

Scheduling Alternatives:

This project has already been deferred from previous years and can likely be deferred again. However, asset failure is inevitable which poses an increased risk to public safety and decreases system reliability.

Ownership Alternatives:

None. This project consists of NPEI assets and is constructed on the public right of way.

Project Name: Cooper, Jill, Jordan & Marie Claude Area - Rebuild
Category: System Renewal

Safety (5.4.3.2.B.2)

The pole line rebuild is designed and constructed in accordance with NPEIs standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Prior to energization, all worked is inspected and signed off by NPEI.

Replacement of deteriorated poles, wires and vintage transformers drastically reduces the likelihood of catastrophic failure, resulting in possible downed wires. Downed wires pose the greatest risk to public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3)

Not Applicable

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This project will be coordinated with the City of Niagara Falls, and applicable third parties.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The pole line rebuild will facilitate greater load transfer capability in NPEI's distribution system.

Environmental Benefits (5.4.3.2.B.2.B.5)

Many of the poles to be replaced were treated with pentachlorophenol, although a great preservative PCP is classified as a probable human carcinogen. Removing and replacing these poles will ensure that no more pentachlorophenol leeches into the soil and ultimately our water supply.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Category – Specific Requirements – System Renewal (5.4.3.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C – SR.i.a)

The proposed project aims to target assets proactively whose condition has deteriorated to the extent that prudent measures must be taken to safeguard the performance of the system and public welfare

Operational Effectiveness - SAIDI and SAIFI will be improved by proactively replacing poles and transformers before failure occurs
Safety - Replacing end of life poles avoids safety issues such as live wire down due to pole failure.
Customer Focus - Replacing poles, transformers and conductors reduces the likelihood of long duration unplanned outages due to equipment failure. Utilization tree wire reduces outages caused by vegetation and wildlife.

In structuring the pole replacement strategy for 2021, NPEI reviewed the prioritized list of pole integrity deficiencies resulting from cyclical inspections. Areas with a high concentration of pole deficiencies are identified as targets for wholesale system renewal rather than individual change-outs. The decision to perform a wholesale rebuild is deemed to be more efficient when the area encompasses distribution transformers also at or near end of life and where system capacity and loss reduction benefits can also

Project Name: Cooper, Jill, Jordan & Marie Claude Area - Rebuild
Category: System Renewal

be realized. The balance of prioritized poles is scheduled for change out under the recurring project for pole replacements.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C – SR.i.b)

This subdivision is comprised of wood poles with pole mounted transformers. The typical useful life of a fully dressed wood pole is 50 years. The majority (63%) of poles are over 50 years old. The typical useful life of a transformer is 40 years, 2 of the transformers are older than 40 years and only two will be replaced. The rest will be re used.

Number of Impacted Customers (5.4.3.2.C – SR.i.c)

Residential 98

Quantitative Customer Impact and Risk (5.4.3.2.C – SR.i.d)

As the assets age and risk of failure increases, frequency of interruptions will increase. Duration of interruptions will also increase depending on what time of day the failure occurs.

Although 98 customers are serviced directly by these assets, in the event of an outage it is possible that the feeder breaker for 3M30 opens which would impact 1883 customers.

Qualitative Customer Impact and Risk (5.4.3.2.C – SR.i.e)

As the assets continue to age beyond their life expectancy, outage frequency and duration becomes an increasingly large risk. Rebuilding a pole line also offers the opportunity to relocate poles to lot lines and, in some cases, out of driveways which improves home owner's enjoyment of their property.

Value of Customer Impact (5.4.3.2.C – SR.i.f)

Value of customer impact is low. A failure would impact 98 residential customers for the duration of the outage. However, if the failure caused the feeder breaker to open, 1883 customers would be effected.

Factors Affecting Project Timing (5.4.3.2.C – SR.ii)

The project timing could be affected by having to re-deploy resources to adjust for unexpected changes in customer demand, such as Road Authority work, subdivision development and commercial connections.

Effect on System O&M Costs (5.4.3.2.C – SR.iii)

The investment to rebuild this area will improve the reliability of electrical supply by reducing the frequency and duration of electrical outages, caused by aging equipment and line contact. This will effectively reduce the O&M costs associated with those outages.

This subdivision experiences outages due to tree and animal contact, many times resulting in crew patrolling the line. Utilizing tree wire primary and spun secondary will help to reduce the occurrence of tree and animal contact which in turn reduces man hours spent.

Project Name: Cooper, Jill, Jordan & Marie Claude Area - Rebuild
Category: System Renewal

Impact on Reliability and Safety (5.4.3.2.C – SR.iv)

Replacing end of life assets will positively impact the duration and frequency of outages. The new pole line is built to current standards, resulting in greater clearances and better safety. Also, replacing end of life assets increases reliability and avoids safety issues due to failing poles and transformers.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C – SR.v)

Alternatives have been discussed in section (5.4.3.2.B.1.d.iii). As demonstrated by NPEIs asset condition assessment, this section of line is at the point of needing a rebuild. There are also other areas of NPEIs service territory that are in similar condition and due for a rebuild. The benefits of the rebuild are clear - building to new standards increases clearances and safety, replacing end of life equipment also increases safety and reliability.

Rebuilding the pole line will avoid and/or reduce power outages. Maintaining the status quo will result in future outages which will lead to unplanned work and customer dissatisfaction.

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.3.2.C – SR.vi)

This project is a like for like replacement. The new line will be built to current standards which means improved pole sizes, hardware and equipment along with greater clearances. It will remain a single phase pole line supplying residential customers.

Project Sign-Off

Prepared By:	Weston Sagle	Authorized By:	
Date:	January 24, 2020	Date:	
		Completion Date:	

Capital Project Summary

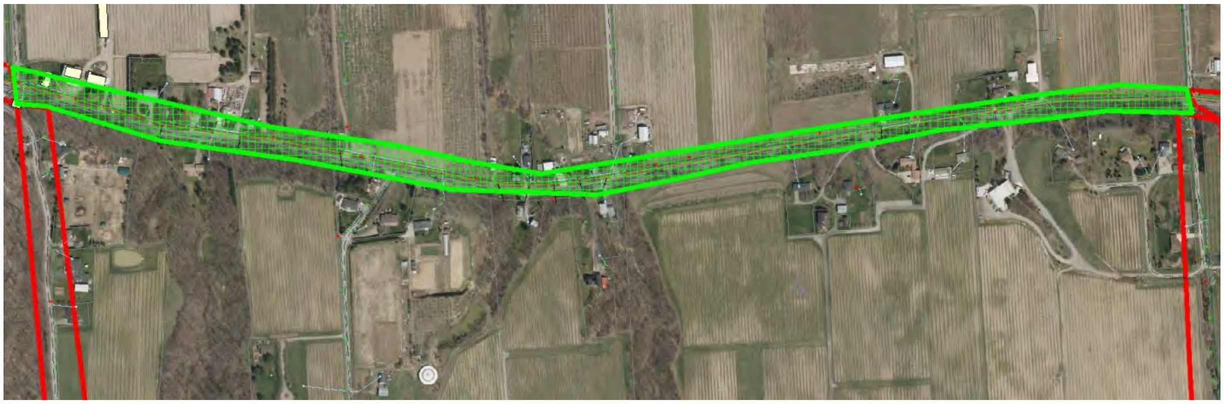
Project Name:	King St. Sann to Merritt Rebuild Phase 2	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	Lincoln

General Information on Project (5.4.3.2.A)

Project Summary	The Project Scope involves the rebuild of existing double circuit 3-phase 27.6 kV and 8.32 kV primary line on King St in place, for approx 1.7 km from Sann Rd going East to Meritt Road. Construction involves the installation of 39 new 50' poles for a double circuit, transfer of existing primary cable on the 8.32 kV, and installation of 1.7 km of new 556 kcmil primary & 3/0 Neutral conductor. The Project is being initiated to provide a capacity increase on the 27.6 kV tie between Vineland Station F1 and Beamsville Station 18-M-1 and replace end of life equipment identified through the pole testing program. The project will be completed in two phases. Benefits include improved supply reliability and flexibility on the system during contingencies and system configuration.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$578,003.64		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	$0.00		
	NPEI Estimated Cost:	$578,003.64		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	28 Customers – 26 Residential (78kVA, assuming 3kVA), 2 Commercial (525 kVA) Approximately 603 kVA			
Project Dates (5.4.3.2.A.iv)	**Start Date:**	January 1, 2021		
	In Service Date:	August 31, 2021		
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$200,000	$200,000	$178,003.64	0

Project Name: King St. Sann to Merritt Rebuild Phase 2
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material



Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints, approvals from applicable authorities and coordination with third parties. Risk mitigation is accomplished by completing the design 4-6 months in advance of construction and project scheduling in conjunction with Operations and Stores, coordinating with the road authority and third parties through the Public Utilities Coordinating Committee (PUCC).

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

In 2018, a similar project was completed in the Lincoln area of Victoria Avenue north of Eighth Avenue. This project was a rebuild and installation of additional circuit along 2km of the system. The total cost was $807,268.73 (approx. $403,634.37 per km).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Project Name: King St. Sann to Merritt Rebuild Phase 2
Category: System Renewal

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver of this project is the age and condition of the existing pole line. The condition and age of the affected poles and transformers is summarized in the tables below.

Poles						
Age	0 - 10	11 - 20	21 - 30	31 - 40	41-50	> 50
Condition	Quantity					
Very Good	1	1	3	7	3	-
Good	-	-	-	-	1	3
Fair	-	-	-	-	-	8
Poor	-	-	-	-	-	9
Very Poor	-	-	-	-	-	3

Transformers					
Age	0 - 10	11 - 20	21 - 30	31 - 40	> 40
Condition	Quantity				
Very Good	2	-	-	-	-
Good	-	-	2	-	-
Fair	-	-	-	2	-
Poor	-	-	1	1	-
Very Poor	-	-	-	-	3

The secondary driver is to provide a capacity increase on the 27.6 kV tie between Vineland Station F1 and Beamsville Station 18M1 by upgrading the primary conductor. This will provide greater flexibility for NPEI's Operators under contingency configurations of our system.

Good Utility Practice (5.4.3.2.B.1.b)

The project was selected by historical knowledge and expertise of our system, which was verified by overlaying the health index of our assets in to our GIS system. With this information a heat map was generated giving a visual representation of areas requiring attention in our system.

As part of our standard engineering practices, pole lines are designed and built to meet or exceed the latest revision of CSA C22.3 No.1. Overhead Systems, which ensures that new distribution system expansions, extensions and replacement are constructed to a level appropriate with the regional climate.

Project Name: King St. Sann to Merritt Rebuild Phase 2
Category: System Renewal

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is medium, this program ranked 9 out 24 projects in our Project Priority Matrix for 2021. NPEI views System Renewal projects as a lower priority than System Access projects, unless the condition of the assets poses an immediately risk to system stability and/or public safety.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Planned replacement of assets compared to replacement at failure offers several advantages. The cost per pole is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums. Proactive replacement allows the entire line to be redesigned and in this case provides an opportunity to increase flexibility in contingency scenarios.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line customers will experience improved reliability; the increased capacity on the circuit will provide greater flexibility and improve restoration times during outages. The risks associated with downed power lines will be drastically reduced with the installation of new poles, wires and associated hardware.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Rebuilding the pole line will greatly increase reliability as many of the assets are near or at end of life. The increased feeder capacity will reduce overall system losses and decrease frequency and duration of outages due to equipment failure.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Replace end of life assets
This option would replace only the assets identified as end of life. Increasing the 27.6kV primary conductor would be a lost opportunity meaning system losses would not be reduced and system flexibility would not be increased. The work would be done piece by piece which would require ongoing maintenance to address issues with aging assets as they arise.

Replace assets upon failure
The only advantage to this option is up front cost savings which pales in comparison to the disadvantages. Overall total costs would be significantly higher as assets would be replaced on an emergency basis. Total quantity of outages would increase due to equipment failures and public safety would be put at risk. The opportunity to increase the feeder tie capacity would be lost.

Scheduling Alternatives:

In the event an unplanned job arises with a higher priority, the schedule can be revised to accommodate. However, as end of life asset replacement is deferred, there is an increased risk to public safety and system reliability decreases.

Project Name: King St. Sann to Merritt Rebuild Phase 2
Category: System Renewal

Ownership Alternatives:

None. This project consists of NPEI assets and is constructed on the public right of way.

Safety (5.4.3.2.B.2)

The pole line rebuild is designed and constructed in accordance with NPEIs standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Prior to energization, all worked is inspected and signed off by NPEI.

Replacement of deteriorated poles, wires and vintage transformers drastically reduces the likelihood of catastrophic failure, resulting in possible downed wires. Downed wires pose the greatest risk to public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3)

Not applicable.

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This project will be coordinated with the Town of Lincoln, Bell Canada, Rogers and NRBN and road authority, where applicable. As well there will be coordination with the customers affected by the transformer replacement.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The pole line rebuild will facilitate greater load transfer capability on NPEI’s distribution system.

Environmental Benefits (5.4.3.2.B.2.B.5)

Many of the poles to be replaced were treated with pentachlorophenol, although a great preservative PCP is classified as a probable human carcinogen. Removing and replacing these poles will ensure that no more pentachlorophenol leeches into the soil and ultimately our water supply.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Category – Specific Requirements – System Renewal (5.4.3.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C – SR.i.a)

The proposed project aims to target assets proactively whose condition has deteriorated to the extent that prudent measures must be taken to safeguard the performance of the system and public welfare

Operational Effectiveness - SAIDI and SAIFI will be improved by proactively replacing poles and transformers before failure occurs
Safety - Replacing end of life poles avoids safety issues such as live wire down due to pole failure.
Customer Focus - Replacing poles and transformers, as well as voltage conversion, reduces the likelihood of long duration unplanned outages due to equipment failure.

Project Name: King St. Sann to Merritt Rebuild Phase 2
Category: System Renewal

In structuring the pole replacement strategy for 2021, NPEI reviewed the prioritized list of pole integrity deficiencies resulting from cyclical inspections. Areas with a high concentration of pole deficiencies are identified as targets for wholesale system renewal rather than individual change-outs. The decision to perform a wholesale rebuild is deemed to be more efficient when the area encompasses distribution transformers also at or near end of life and where system capacity and loss reduction benefits can also be realized. The balance of prioritized poles is scheduled for change out under the recurring project for pole replacements.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C – SR.i.b)

This pole line is comprised of wood poles with pole mounted transformers. The typical useful life of a fully dressed wood pole is 50 years. The majority (59%) of poles are over 50 years old. The typical useful life of a transformer is 40 years, although 27% of the transformer are over 40 years old, 45% of them are in "poor" or "very poor" condition.

Number of Impacted Customers (5.4.3.2.C – SR.i.c)

28 Customers – 26 Residential & 2 Commercial

Quantitative Customer Impact and Risk (5.4.3.2.C – SR.i.d)

As the assets age and risk of failure increases, frequency of interruptions will increase. Duration of interruptions will also increase depending on what time of day the failure occurs.

Although 28 customers are serviced directly by these assets, in the event of an outage it is possible that the feeder breaker for 4501F1 opens which would impact 2,161 customers.

Qualitative Customer Impact and Risk (5.4.3.2.C – SR.i.e)

As the assets continue to age beyond their life expectancy, outage frequency and duration becomes an increasingly large risk.

Value of Customer Impact (5.4.3.2.C – SR.i.f)

Value of customer impact is low. A failure would impact 26 residential customers and 2 commercial customers for the duration of the outage. However, if the failure caused the feeder breaker to open, 2,161 customers would be affected.

Factors Affecting Project Timing (5.4.3.2.C – SR.ii)

The project timing could be impacted by having to re-deploy resources to adjust for unexpected changes in customer demand, such as Road Authority work, subdivision development and commercial connections.

Effect on System O&M Costs (5.4.3.2.C – SR.iii)

The investment to rebuild King St. will improve the reliability of electrical supply by reducing the frequency and duration of electrical outages, caused by aging equipment. This will effectively reduce the O&M costs associated with those outages.

Project Name: King St. Sann to Merritt Rebuild Phase 2
Category: System Renewal

Impact on Reliability and Safety (5.4.3.2.C – SR.iv)

The new pole line is built to current standards, resulting in greater clearances and better safety. Also, replacing end of life assets increases reliability and avoids safety issues due to failing poles and transformers.

By adding the increased capacity on the tie circuit more flexibility is achieved in contingency scenarios, ultimately improving reliability for customers on either Feeder (4501 F1 & 18M1).

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C – SR.v)

Alternatives have been discussed in section (5.4.3.2.B.1.d.iii). As demonstrated by NPEIs asset condition assessment, this section of line is at the point of needing a rebuild. There are also other areas of NPEIs service territory that are in similar condition and due for a rebuild. The benefits of the rebuild are clear - building to new standards increases clearances and safety and replacing end of life equipment also increases safety and reliability.

Rebuilding the pole line will avoid and/or reduce power outages. Maintaining the status quo will result in future outages which will lead to unplanned work and customer dissatisfaction.

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.3.2.C – SR.vi)

Replacing the existing infrastructure like for like is a wasted opportunity. By not taking advantage of increasing the capacity of the tie circuit, the opportunity will be lost. If this ever became a constraint issue in the future, the cost to re-conductor the line would be significantly higher than the cost to complete the work during this rebuild project.

Project Sign-Off

Prepared By:	Paul Uguccioni	Authorized By:	
Date:	January 29, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	Kiosk Replacement with Pad Mounted Transformers	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	Niagara Falls

General Information on Project (5.4.3.2.A)

Project Summary	Prior to the advent of pad-mounted Transformer & Switchgear Equipment, loads that were too large for pole mounted equipment, or areas serviced from underground primary distribution systems, were supplied by masonry enclosures housing high voltage transformation, switching & protection apparatus, and secondary distribution equipment, known as the Kiosk. These block structures were meant to provide Public Safety but over time, the structures deteriorate and warrant replacement. These are prioritized utilizing the results of a 5-year Conditional Assessment Survey last completed in 2018. This Capital Program is an integral part of the remediation of underground distribution systems, increasing longevity and reliability within the area serviced. As these legacy components are replaced, safety, reliability and service quality are significantly improved. For 2021 the plan is to replace approximately 11 units.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$646,096.00		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** **NPEI Estimated Cost:**	$0.00 $646,096.00		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	The typical Kiosk would contain 150 – 300 kVA transformers, typically serving 1 larger Commercial Customer but in some cases multiple customers.			
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 1, 2021 **In Service Date:** December 31, 2021			
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$200,000	$123,048	$200,000	$123,048

Project Name: Kiosk Replacement with Pad Mounted Transformers
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material

Project Name: Kiosk Replacement with Pad Mounted Transformers
Category: System Renewal

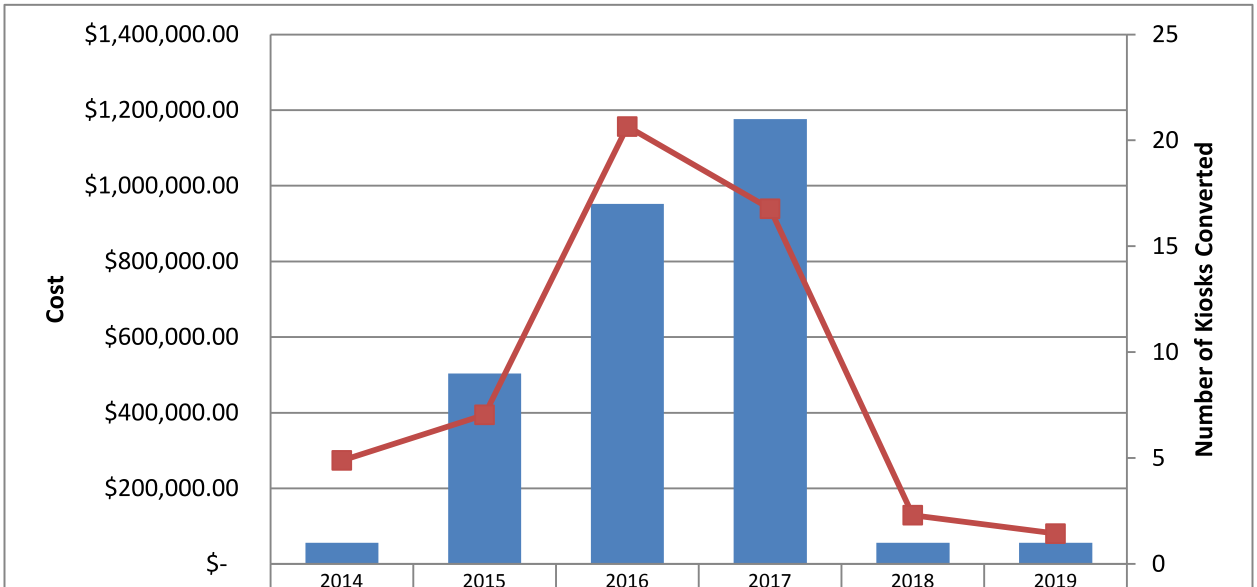
Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints, approvals from applicable authorities and coordination with third parties. Risk mitigation is accomplished by knowing which Kiosks will be replaced in a prioritized manner and completing the design 4-6 months in advance of construction. Risks related to labour constraints are further reduced as these projects are completed by a third party contractor familiar with replacing NPEI Kiosks.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

The cost can vary from kiosk to kiosk as each project is unique. In some cases the rebuild may only involve the installation of new pad mounted distribution in place of the existing kiosk. While, in other cases a new location for the new equipment may be required to improve accessibility.

Below is a breakdown of historical Kiosk Replacements over the past 6 years:



	2014	2015	2016	2017	2018	2019
Kiosks Converted	1	9	17	21	1	1
Cost	$273,930.70	$394,424.16	$1,156,448.7	$939,197.14	$129,059.47	$80,283.10

This equates to an average cost of $55,061.91 per Kiosk.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Project Name: Kiosk Replacement with Pad Mounted Transformers
Category: System Renewal

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver for this project is safety of NPEI's Operations Staff. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain.

The secondary driver for this project is asset condition and system reliability. The equipment deployed within these Kiosks are obsolete and sometimes difficult to source. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

Good Utility Practice (5.4.3.2.B.1.b)

This program was started in response to growing safety concerns from our Operations staff. These block structures were meant to provide Public Safety but over time, the structures deteriorate and warrant replacement. The units are prioritized utilizing the results of a 5-year Conditional Assessment Survey last completed in 2018.

Rebuilding the Kiosk vaults will be completed in accordance with NPEI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. The units are replaced with standard distribution equipment used throughout the NPEI system. This investment will ensure that the equipment will operate in a safe manner and significantly reduce the probability of injuries to workers and the public.

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is High, due to these assets using obsolete equipment and posing a risk to system stability and/or public safety.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Planned replacement of assets compared to replacement at failure offers several advantages. The cost per Kiosk conversion is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums. Proactive replacement allows the entire line to be redesigned and in this case a voltage conversion.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Planned replacement of assets compared to replacement at failure offers several advantages. The cost per Kiosk conversion is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums.

Project Name: Kiosk Replacement with Pad Mounted Transformers
Category: System Renewal

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By converting Kiosks to updated standard distribution equipment, customers will experience improved reliability and improved restoration times during outages**.** If these assets are run to failure or becomes critical, the kiosk may have to be de-energized, thus affecting system reliability for customers.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Replace assets upon failure
The only advantage to this option is up front cost savings which pales in comparison to the disadvantages. Overall total costs would be significantly higher as assets would be replaced on an emergency basis and as the equipment is obsolete, it would never be a like-for-like replacement. Total quantity of outages would increase due to equipment failures and public safety would be put at risk.

Repair Only Structural Damages
Although this would address the majority of safety concerns for the general public, it does not address the core goal of this program, which is to remove the safety hazard associated with working inside these vaults for our Operations Staff.

Scheduling Alternatives:

As this work is completed by third party contractors, there is flexibility to shift the project throughout the designated year. As well, with a target of 11 Kiosks there will be flexibility on project deployment.

Ownership Alternatives:

None. This project consists solely of NPEI's assets.

Safety (5.4.3.2.B.2)

NPEI Operations staff Safety is the primary driver for this project as the equipment within these kiosks it is becoming increasingly difficult to safely and effectively maintain.

Rebuilding the Kiosk vaults will be completed in accordance with NPEI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. The units are replaced with standard distribution equipment used throughout the NPEI system. This investment will ensure that the equipment will operate in a safe manner and significantly reduce the probability of injuries to workers and the public.

Cyber-Security and Privacy (5.4.3.2.B.3)

Not Applicable

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This project will be coordinated with the property owner in which the Kiosk is located and the customers affected by the work. As well coordination is required with the third party contractor completing the work.

Project Name: Kiosk Replacement with Pad Mounted Transformers
Category: System Renewal

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

There would be no immediate opportunity for future technology and/or future operational requirements. However, as the equipment is converted to standard distribution equipment used throughout our system it would be easier to adapt any future technology.

Environmental Benefits (5.4.3.2.B.2.B.5)

Not applicable

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable

Category – Specific Requirements – System Renewal (5.4.3.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C – SR.i.a)

The Kiosks contain equipment that is now obsolete and in many cases at the end of their useful life. All Kiosks are inspected on a 5-year Conditional Assessment Survey. Replacements are prioritized by the results of these assessments.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C – SR.i.b)

As kiosks are considered obsolete, there is no typical life cycle for this structure. NPEI has never replaced a kiosk for a like-for-like replacement and has only converted them using standard distribution equipment.

Number of Impacted Customers (5.4.3.2.C – SR.i.c)

The typical Kiosk would contain 150 – 300 kVA transformers, typically serving 1 larger Commercial Customer but in some cases multiple commercial or residential customers.

Quantitative Customer Impact and Risk (5.4.3.2.C – SR.i.d)

Outages that occur with Kiosks are rare as the equipment is contained in a vault. However, when they do occur, they tend to last a long time due to the equipment being obsolete and limited accessibility as a result of the original method of construction. If the Kiosks are not replaced in a timely manner there could be structural failures which could have significant impact on reliability and safety.

These risks are minimized by proactively replacing and converting these assets to standard distribution equipment (i.e. pad mounted distribution transformers, junction Units, etc.)

Qualitative Customer Impact and Risk (5.4.3.2.C – SR.i.e)

Outages that occur with Kiosks are rare as the equipment is contained in a vault. However, as these assets continue to age and deteriorate the likely hood of a failure increases and public safety can become an issue.

These risks are minimized by proactively replacing and converting these assets to standard distribution equipment (i.e. pad mounted distribution transformers, junction units, etc.).

Project Name: Kiosk Replacement with Pad Mounted Transformers
Category: System Renewal

Value of Customer Impact (5.4.3.2.C – SR.i.f)

Value of customer impact is medium.

As the Kiosks slowly deteriorate, they increasing become a risk to public safety.

An equipment failure would impact only the downstream customers of the affected Kiosk for the duration of the outage. However, if the failure caused the feeder breaker to open, thousands of customers would be affected. As discussed previously when equipment failures do occur, they tend to last a long time due to the equipment being obsolete and limited accessibility as a result of the original method of construction.

Factors Affecting Project Timing (5.4.3.2.C – SR.ii)

Kiosks are primarily located on private property and exclusively service that property. Coordination with the owners of the property is required to ensure outages are minimized and managed appropriately. As only one Kiosk is converted at a time, there is flexibility on the order of conversation, based on customer availability.

Effect on System O&M Costs (5.4.3.2.C – SR.iii)

The investment to convert Kiosks will improve the reliability of electrical supply by reducing the duration of electrical outages, caused by aging equipment. This will effectively reduce the O&M costs associated with those outages.

As NPEI continues to convert remaining Kiosks, O&M savings are realized through reduction carrying costs of materials and furnishing of spare parts.

Impact on Reliability and Safety (5.4.3.2.C – SR.iv)

Safety of NPEI's Operations Staff is the primary focus of this program. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. The equipment deployed within these Kiosks is obsolete and sometimes difficult to source. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

By converting the remaining Kiosks within NPEI's service territory, the safety hazard will be eliminated and system reliability will be increased as new standard distribution equipment is installed.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C – SR.v)

Alternatives have been discussed in section (5.4.3.2.B.1.d.iii). The benefits of converting the remaining Kiosks are clear - new standard distribution equipment improves Operational Staff and public safety, replacing end of life/obsolete equipment also increases safety and reliability.

Converting Kiosks will avoid and/or reduce power outages and reduce their duration. Maintaining the status quo will result in future outages which will lead to lengthy unplanned work and customer dissatisfaction.

Project Name: Kiosk Replacement with Pad Mounted Transformers
Category: System Renewal

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.3.2.C – SR.vi)			
Not applicable as Kiosks are an obsolete solution.			
Project Sign-Off			
Prepared By:	Paul Uguccioni	Authorized By:	
Date:	January 28, 2020	Date:	
		Completion Date:	

Capital Project Summary

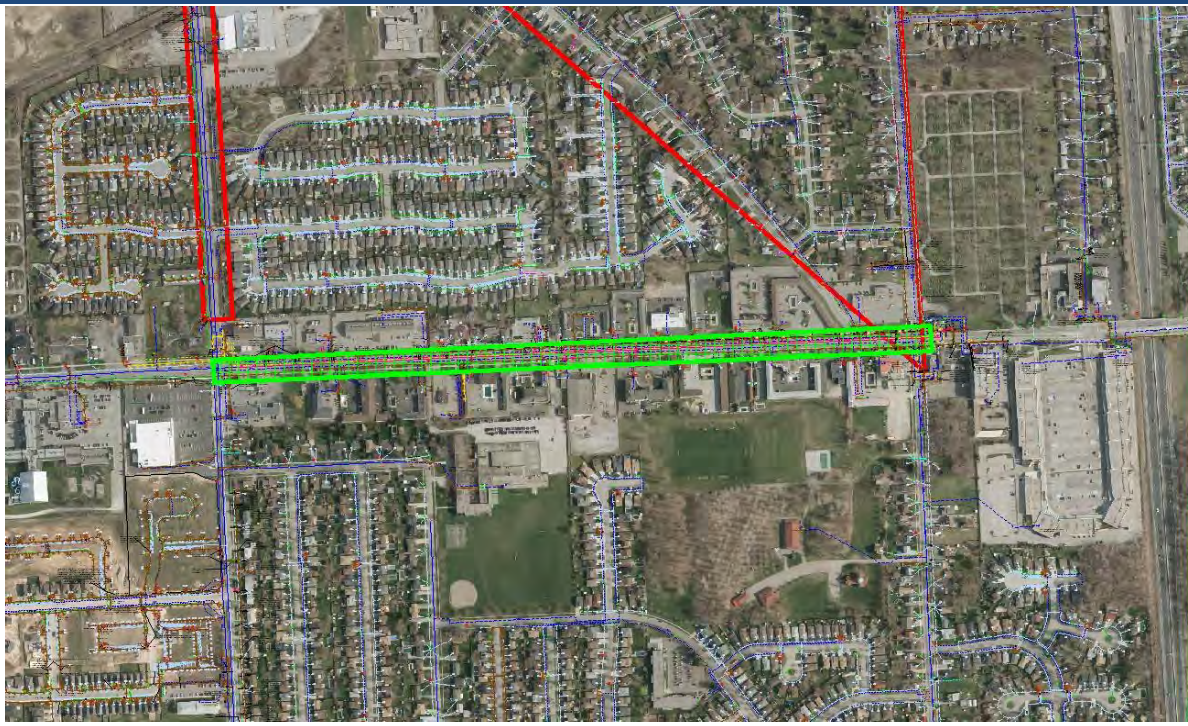
Project Name:	Lundy's Lane - Phase 1 (Montrose Rd. to Tx. #800177)	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	Niagara Falls

General Information on Project (5.4.4.2.A)

Project Summary	The project scope involves the rebuild of the existing 200 A underground circuit on Lundy's Lane between Montrose Rd and Kalar Rd. Construction involves the replacement of 400 m of underground primary cable in the same alignment. This is the first phase of a project that will see the replacement of two entire 200 A underground circuits (North and South sides) along Lundy's Lane from Montrose Road to Kalar Road. In total, 2.1 km of 3 phase underground primary will be replaced. Benefits include replacement of aging equipment, improved supply reliability, Public & Personnel safety and flexibility on the system during contingencies and system configuration.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$536,750.00		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	$0.00		
	NPEI Estimated Cost:	$536,750.00		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	Residential - 8, GS<50kW - 54, GS>50kW - 18			
Project Dates (5.4.3.2.A.iv)	**Start Date:**	July 1, 2021		
	In Service Date:	December 31, 2021		
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	0	0	$268,375	$268,375

Project Name: Lundy's Lane - Phase 1 (Montrose Rd. to Tx. #800177)
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material



Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints, approvals from applicable authorities and coordination with third parties. Risk mitigation is accomplished by completing the design 4-6 months in advance of construction and project scheduling in conjunction with Operations and Stores, coordinating with the road authority and third parties through the Public Utilities Coordinating Committee (PUCC).

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

In 2016/17, a similar project was completed in the Niagara Falls area of River Road and Bridge Street. This project involved replacement/reconstruction of new underground distribution system and included replacement 1km of 3 phase circuit. The total cost was $864,500.50 (approx. $432,250.25 per 500m).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Project Name: Lundy's Lane - Phase 1 (Montrose Rd. to Tx. #800177)
Category: System Renewal

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary investment driver is risk of failure. NPEI's 2018 Asset Condition Assessment indentifies approximately 100 km of underground cable as flagged for action over the next 10 years. Evenly distributed, this represents approximately 10 km of cable per year. The section of direct buried cable between Montrose and Kalar was installed in 1967, making it 53 years old, well beyond its useful life.

The secondary investment driver is to reduce unplanned outages for our customers. Lundy's Lane is a major tourist area, housing mostly restaurants and hotels. Outages can be planned to replace end of life direct buried cables and new cables will be installed in a duct structure.

Good Utility Practice (5.4.3.2.B.1.b)

The objective of the program is develop a more resilient distribution system (cables in duct as opposed to direct buried) while addressing existing reliability and performance concerns (direct buried end of life cable).

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is low, this program ranked 19 out 24 projects in our Project Priority Matrix for 2021. NPEI views System Renewal projects as a lower priority than System Access projects, unless the condition of the assets poses an immediately risk to system stability and/or public safety.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

System operation efficiency will increase as a result of replacing vintage, undersized, end of life cables with new, properly sized cables installed in conduit. By planning work in advance, competitive bids can be received and emergency replacement minimized or eliminated which offers cost savings.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Customers will benefit with new, reliable electrical infrastructure. The vast majority of customers in this area are motels and restaurants. A stable electricity supply is crucial to their operations. The current supply has served well, but has exceeded its maximum expected useful life.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Once direct buried cable reaches end of life, failures occur more frequently resulting in unplanned customer outages. By replacing cables now, in phases, work can be planned and outages minimized and coordinated with customers. The result is a reduction in both frequency and duration of outages.

Project Name: Lundy's Lane - Phase 1 (Montrose Rd. to Tx. #800177)
Category: System Renewal

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

One alternative is to abandon the underground infrastructure and build a new overhead pole line. NPEI had begun this process, but the Lundy's Lane BIA protested by blocking vehicles. Being a tourist area, aesthetic is very important, so NPEI engaged the Lundy's Lane BIA and agreed to replace existing underground with new underground.

Another alternative is to replace plant upon failure. The only advantage is spending less up front. The disadvantages are higher total costs, increased frequency and duration of outages, reduced customer satisfaction, reduced overall safety and reduced system reliability.

Scheduling Alternatives:

If an unplanned job has significantly higher priority, a decision can be made to defer this job. However, risk of failure continues to increase which is likely to lead to higher OM&A costs.

Ownership Alternatives:

None. This project consists of NPEI assets and is constructed on the public right of way.

Safety (5.4.3.2.B.2)

All work is performed by licensed contractors in accordance with NPEIs standards and Ontario Regulation 22/04 to ensure no undue safety hazards. All underground work is coordinated with third parties (gas, telecom, water).

Cyber-Security and Privacy (5.4.3.2.B.3)

Not applicable.

Co-ordination and Interoperability - **Co-ordination with utilities, regional planning and/or links with 3rd parties** (5.4.3.2.B.4.a)

This program will be coordinated with the City of Niagara Falls, the Niagara Region, Bell Canada, Ontario Power Generation, Rogers, Cogeco and NRBN. Customers in the affected area will also be notified. NPEI attends quarterly meetings with the Lundy's Lane BIA.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

Not applicable.

Environmental Benefits (5.4.3.2.B.2.B.5)

The Lundy's Lane BIA has been regreening Lundy's Lane by planting trees. Overhead infrastructure would have interfered with these trees, by going underground, more trees can be planted, benefiting the environment.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Project Name: Lundy's Lane - Phase 1 (Montrose Rd. to Tx. #800177)
Category: System Renewal

Category – Specific Requirements – System Renewal (5.4.4.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.4.2.C – SR.i.a)

NPEI's 2018 Asset Condition Assessment indentifies approximately 100 km of underground cable as flagged for action over the next 10 years. Evenly distributed, this represents approximately 10 km of cable per year. Although this cable is still demonstrating satisfactory performance, it has exceeded its useful life by 1.5 times. Continuous use of this cable increases risk of failure which will impact both SAIDI and SAIFI.

Asset Condition Relative to Typical Life Cycle (5.4.4.2.C – SR.i.b)

The typical life cycle of direct buried cable is 35. NPEI's asset condition assessment for underground cables was strictly based on age. As shown in the ACA, approximately 100 km of cable is ranked as "poor" or "very poor" condition. The cable to be replaced by this program is 53 years old, or 1.5 times beyond its useful life.

Number of Impacted Customers (5.4.4.2.C – SR.i.c)

Approximately 72 commercial (54 - GS<50kW and 18 - GS>50kW) and 8 residential customers will be impacted.

Quantitative Customer Impact and Risk (5.4.4.2.C – SR.i.d)

Replacing end of life cable will result fewer outages of shorter duration.

Qualitative Customer Impact and Risk (5.4.4.2.C – SR.i.e)

This project is partially driven by the Lundy's Lane BIA. Customer satisfaction will increase dramatically as the new infrastructure will be both reliable and aesthetically pleasing.

Value of Customer Impact (5.4.4.2.C – SR.i.f)

The value of customer impact is high. The vast majority of customers are businesses dealing directly with customers (food and hospitality) and cannot operate without electricity.

Factors Affecting Project Timing (5.4.4.2.C – SR.ii)

Higher priority projects may affect the timing. Adverse weather, availability of contractors, other work being done in the area.

Effect on System O&M Costs (5.4.4.2.C – SR.iii)

Direct buried cable is very challenging to work on. Isolating and fixing faults is a time consuming process involving a lot of man hours. Replacement of end of life direct buried cable will lead to decreased O&M costs.

Impact on Reliability and Safety (5.4.4.2.C – SR.iv)

Reliability and safety will both increase. 50+ year old cable is much more likely to fault than new cable, resulting in safety and reliability issues.

Project Name: Lundy's Lane - Phase 1 (Montrose Rd. to Tx. #800177)
Category: System Renewal

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.4.2.C – SR.v)

Proactive cable replacement is a excellent way to spread the cost of the upgrade while minimizing downtime for NPEI's customers. The benefits of cable installed in duct vs direct buried are clear. The project is part of a larger project which is the general improvement of Lundy's Lane.

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.4.2.C – SR.vi)

Like for like renewal would be installing more direct buried cable. Direct buried does not meet our current standards and is an antiquated way of serving customers. The initial cost may be lower, but over time O&M costs are higher.

Project Sign-Off

Prepared By:	Weston Sagle	Authorized By:	
Date:	January 31, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	McRae Rebuild Phase 2	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	Niagara Falls

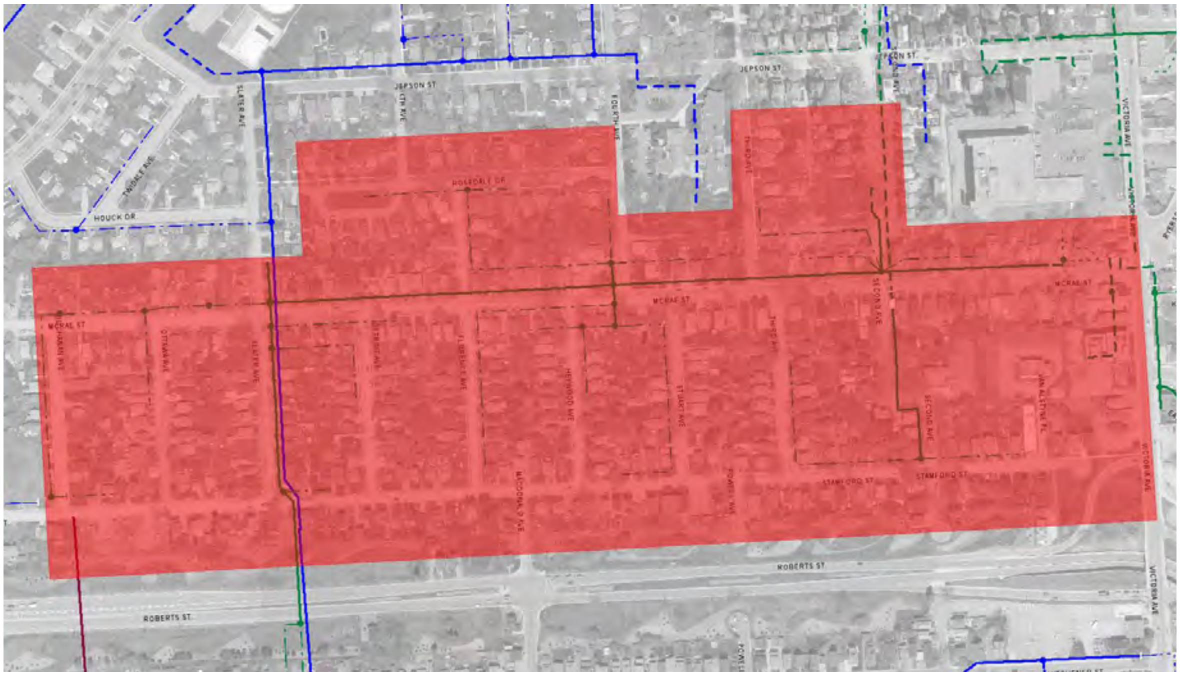
General Information on Project (5.4.4.2.A)

Project Summary	Project scope involves the replacement of a three phase 4.16 kV circuit (0.75 km) as well as 2.25 km of single phase 2.4 kV circuit (built in 1960). The new overhead line will be constructed to 13.8 kV standards with dual voltage transformers using 25 new 45' and 60 new 40' wood poles. Construction will assume the same alignment as the existing pole lines and include the following side streets; Second Ave, Third Ave, Stuart Ave, Fourth Ave, Heywood Ave, Florence, Detroit Ave, Ottawa Ave, Buchanan Ave, Stamford St, McRae St and Rosedale Dr. The area will be connected to the 13.8 kV system at a future date. The project includes replacement of 26 single phase transformers, installation of 3 km of secondary bus and direct transfer of 465 residential services to the new bus. Due to the size of this project, it will be split into three phases. Benefits include reduced system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area.
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:** $466,673.22 (Cost of this Phase)
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** $0.00 **NPEI Estimated Cost:** $466,673.22
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	The total customers affected across all three phases is 465 residential customers / 1395 kVA (assuming 3 kVA per customer)
Project Dates (5.4.3.2.A.iv)	**Start Date:** April 1, 2021 **In Service Date:** December 31 2021

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	$100,000	$150,000	$216,673.22

Images, Drawings, Maps, & Other Reference Material

Project Name: McRae Rebuild Phase 2
Category: System Renewal



Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints, approvals from applicable authorities and coordination with third parties. Risk mitigation is accomplished by completing the design 4-6 months in advance of construction and project scheduling in conjunction with Operations and Stores, coordinating with the road authority and third parties through the Public Utilities Coordinating Committee (PUCC).

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

In 2019, a similar project was completed in the Niagara Falls area of McLeod Road and Drummond Road. This project was Phase 3 of a multi-phase system rebuild/voltage conversion and included replacement of 76 poles and 250 customers. The total cost this phase was $828,037.52 (approx. $10,895.23 per pole and $3,312.15 per customer).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Project Name: McRae Rebuild Phase 2
Category: System Renewal

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver of this project is the age and condition of the existing pole line. The condition and age of the affected poles and transformers is summarized in the tables below.

Poles						
Age	0 - 10	11 - 20	21 - 30	31 - 40	41-50	> 50
Condition	Quantity					
Very Good	5	5	31	16	3	1
Good	2	1	19	8	7	6
Fair	-	-	-	-	-	12
Poor	-	-	-	1	1	3
Very Poor	-	-	-	-	-	9

Transformers					
Age	0 - 10	11 - 20	21 - 30	31 - 40	> 40
Condition	Quantity				
Very Good	2	1	-	-	-
Good	-	-	11	-	-
Fair	-	-	3	3	-
Poor	-	-	-	-	2
Very Poor	-	-	-	-	6

Secondary driver is preparing the area for a future voltage conversion. The existing line is single phase 2.4 kV and three phase 4.16kV, the new line will be single phase 8 kV and three phase 13.8kV. Standardizing the voltage across the city offers tremendous benefit in terms equipment standardization, lower system losses, increased clearances and overall safety.

Good Utility Practice (5.4.3.2.B.1.b)

The project was selected by historical knowledge and expertise of our system, which was verified by overlaying the health index of our assets in to our GIS system. With this information a heat map was generated giving a visual representation of areas requiring attention in our system.

As part of our standard engineering practices, pole lines are designed and built to meet or exceed the latest revision of CSA C22.3 No.1. Overhead Systems, which ensures that new distribution system expansions, extensions and replacement are constructed to a level appropriate with the regional climate.

Project Name: McRae Rebuild Phase 2
Category: System Renewal

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is medium, this program ranked 8 out of 24 projects in our Project Priority Matrix for 2021. NPEI views System Renewal projects as a lower priority than System Access projects, unless the condition of the assets poses an immediately risk to system stability and/or public safety. Within System Renewal projects this projects ranks as high priority as it is a large project spanning over multiple phases across multiple budget years.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Planned replacement of assets compared to replacement at failure offers several advantages. The cost per pole is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums. Proactive replacement allows the entire line to be redesigned and in this case a voltage conversion.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line customers will experience improved reliability, the provision for future voltage conversion will provide greater flexibility and improve restoration times during outages. The risks associated with downed power lines will be drastically reduced with the installation of new poles, wires and associated hardware.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Rebuilding the pole line will greatly increase reliability as many of the assets are near or at end of life. The provision for voltage conversion will reduce overall system losses and decrease frequency and duration of outages due to equipment failure.

The area is currently supplied by a 4.16 kV feeder out of NPEI's Lewis MS on the F74 circuit as well as the F3 circuit out of NPEI's Armoury MS. The future voltage conversion will allow for the area to be fed from either the 12M6 Feeder out of Stanley TS or from the 3M14 Murray TS on a contingency scenario. Having the ability to feed the area from two different TS will provide greater flexibility and improve restoration times during outages.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Replace end of life assets
This option would replace only the assets identified as end of life. Future voltage conversion would be a lost opportunity meaning system losses would not be reduced and system stability would not be increased. The work would be done piece by piece which would require ongoing maintenance to address issues with aging assets as they arise.

Replace assets upon failure

The only advantage to this option is up front cost savings which pales in comparison to the disadvantages. Overall total costs would be significantly higher as assets would be replaced on an emergency basis. Total quantity of outages would increase due to equipment failures and public safety would be put at risk. Voltage conversion opportunity would be lost.

Project Name: McRae Rebuild Phase 2
Category: System Renewal

Scheduling Alternatives:

In the event an unplanned job arises with a higher priority, the schedule can be revised to accommodate. However, as end of life asset replacement is deferred, there is an increased risk to public safety and system reliability decreases.

Ownership Alternatives:

None. This project consists of NPEI assets and is constructed on the public right of way.

Safety (5.4.3.2.B.2)

The pole line rebuild is designed and constructed in accordance with NPEIs standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Prior to energization, all worked is inspected and signed off by NPEI.

Replacement of deteriorated poles, wires and vintage transformers drastically reduces the likelihood of catastrophic failure, resulting in possible downed wires. Downed wires pose the greatest risk to public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3)

Not applicable.

Co-ordination and Interoperability - **Co-ordination with utilities, regional planning and/or links with 3rd parties** (5.4.3.2.B.4.a)

This project will be coordinated with the City of Niagara Falls, Bell Canada, Rogers and NRBN and road authority, where applicable. As well there will be coordination with the customers affected by this rebuild project.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The pole line rebuild will facilitate more load transfer capability of NPEI's distribution system.

Environmental Benefits (5.4.3.2.B.2.B.5)

Many of the poles to be replaced were treated with pentachlorophenol, although a great preservative PCP is classified as a probable human carcinogen. Removing and replacing these poles will ensure that no more pentachlorophenol leeches into the soil and ultimately our water supply.

The future voltage conversion will reduce system losses, ultimately requiring fewer resources. Depending on the current supply mix, this is beneficial for the environment.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Project Name: McRae Rebuild Phase 2
Category: System Renewal

Category – Specific Requirements – System Renewal (5.4.4.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.4.2.C – SR.i.a)

The proposed project aims to target assets proactively whose condition has deteriorated to the extent that prudent measures must be taken to safeguard the performance of the system and public welfare

Operational Effectiveness - SAIDI and SAIFI will be improved by proactively replacing poles and transformers before failure occurs
Safety - Replacing end of life poles avoids safety issues such as live wire down due to pole failure.
Customer Focus - Replacing poles and transformers, as well as voltage conversion, reduces the likelihood of long duration unplanned outages due to equipment failure.

In structuring the pole replacement strategy for 2021, NPEI reviewed the prioritized list of pole integrity deficiencies resulting from cyclical inspections. Areas with a high concentration of pole deficiencies are identified as targets for wholesale system renewal rather than individual change-outs. The decision to perform a wholesale rebuild is deemed to be more efficient when the area encompasses distribution transformers also at or near end of life and where system capacity and loss reduction benefits can also be realized. The balance of prioritized poles is scheduled for change out under the recurring project for pole replacements.

Asset Condition Relative to Typical Life Cycle (5.4.4.2.C – SR.i.b)

This subdivision is comprised of wood poles with pole mounted transformers. The typical useful life of a fully dressed wood pole is 50 years. Approximately one third of poles are over 50 years old. The typical useful life of a transformer is 40 years, 8 of the transformers are older than 40 years.

Number of Impacted Customers (5.4.4.2.C – SR.i.c)

The entire project across all phases will affect a total of 465 residential customers.

68 residential customers on the F74 Feeder out of Lewis MS
397 residential customers on the F3 Feeder out of Armoury MS

Quantitative Customer Impact and Risk (5.4.4.2.C – SR.i.d)

As the assets age and risk of failure increases, frequency of interruptions will increase. Duration of interruptions will also increase depending on what time of day the failure occurs.

68 customers are serviced directly by these assets on the F74 circuit, in the event of an outage it is possible that if the feeder breaker F74 opens 145 customers would be impacted.

397 customers are serviced directly by these assets on the F3 circuit, in the event of an outage it is possible that if the feeder breaker F3 opens 426 customers would be impacted.

Project Name: McRae Rebuild Phase 2
Category: System Renewal

Qualitative Customer Impact and Risk (5.4.4.2.C – SR.i.e)

As the assets continue to age beyond their life expectancy, outage frequency and duration becomes an increasingly large risk.

Value of Customer Impact (5.4.4.2.C – SR.i.f)

Value of customer impact is medium.

A failure would impact of one of the assets on the F74 circuit would impact 68 residential customers for the duration of the outage and a failure on one of the assets on the F3 circuit would impact 397 customers. However, if the failure caused either the F74 or F3 feeder breaker to open, 145 and 426 customers respectively would be affected.

Factors Affecting Project Timing (5.4.4.2.C – SR.ii)

The project timing could be impacted by having to re-deploy resources to adjust for unexpected changes in customer demand, such as Road Authority work, subdivision development and commercial connections.

Effect on System O&M Costs (5.4.4.2.C – SR.iii)

The investment to rebuild McCrae and surrounding area will improve the reliability of electrical supply by reducing the frequency and duration of electrical outages, caused by aging equipment. This will effectively reduce the O&M costs associated with those outages.

As NPEI continues to convert remaining 4 kV infrastructure to 13.8 kV, O&M savings are realized through reduction carrying costs of materials and furnishing of spare parts.

Impact on Reliability and Safety (5.4.4.2.C – SR.iv)

The new pole line is built to current standards, resulting in greater clearances and better safety. Also, replacing end of life assets increases reliability and avoids safety issues due to failing poles and transformers.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.4.2.C – SR.v)

Alternatives have been discussed in section (5.4.3.2.B.1.d.iii). As demonstrated by NPEIs asset condition assessment, this section of line is at the point of needing a rebuild. There are also other areas of NPEIs service territory that are in similar condition and due for a rebuild. The benefits of the rebuild are clear - the future voltage conversion increases reliability, building to new standards increases clearances and safety, replacing end of life equipment also increases safety and reliability.

Rebuilding the pole line will avoid and/or reduce power outages. Maintaining the status quo will result in future outages which will lead to unplanned work and customer dissatisfaction.

Project Name: McRae Rebuild Phase 2
Category: System Renewal

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.4.2.C – SR.vi)

Replacing the existing infrastructure like for like is a wasted opportunity. The area of this project is surrounded by 13.8 kV, and special provisions are in place to service this area. Eliminating the 4 kV infrastructure is a secondary driver of this project and if not done during this rebuild, it will be done at some time in the future at a much higher overall cost.

Project Sign-Off

Prepared By:	Paul Uguccioni	Authorized By:	
Date:	January 30, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	Pad-Mounted Transformer Replacement	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	All

General Information on Project (5.4.3.2.A)

Project Summary	The Underground Equipment Inspection Program has identified a requirement for replacement of ageing pad-mount transformers, due to corrosion and potential contamination issues. NPEI's Asset Condition Assessment has indicated a flagged for action rate of approximately 15 units per year. Project scope involves the identification of small pad-mount transformers identified as in poor condition and replacement to current standards, using equipment constructed of Stainless Steel to avoid corrosion issues. NPEI's small pad mount transformer population is approximately 2 to 1 single phase small pad mounts to three phase pad mounts. NPEI's target is to replace 5 three phase units per year. Benefits of the program include increased system reliability, Public & Personnel safety, and functionality.
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:** $277,762.23
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** $0.00 **NPEI Estimated Cost:** $277,762.23
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	Pad-mounted transformers range in size from 50 kVA – 1500 kVA. NPEI's target is to replace 5 three phase units per year. The customers can range from 1 large commercial to approximately 10-12 residential customers per pad mount transformer.
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 1, 2021 **In Service Date:** December 31, 2021

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$120,000	$120,000	$18,881.12	$18,881.11

Project Name: Pad-Mounted Transformer Replacement
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints. Manufacturers require 16-20 weeks for delivery for each unit pad-mount transformer. Material risk is mitigated by following NPEI's standard practice of ordering transformers on a regular basis and having spares on hand. By having a list of tagged transformers for replacement, labour resources can be planned accordingly to tackle transformers in a logical and cost effective manner.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

The pad mount transformer replacement program is new to NPEI, so information from equivalent projects does not exist at this time. By examining historical data, the average cost to replace a pad mount transformer is $55,552.44.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not Applicable

Project Name: Pad-Mounted Transformer Replacement
Category: System Renewal

Leave to Construct Approval (5.4.3.2.A.viii)

Not Applicable

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

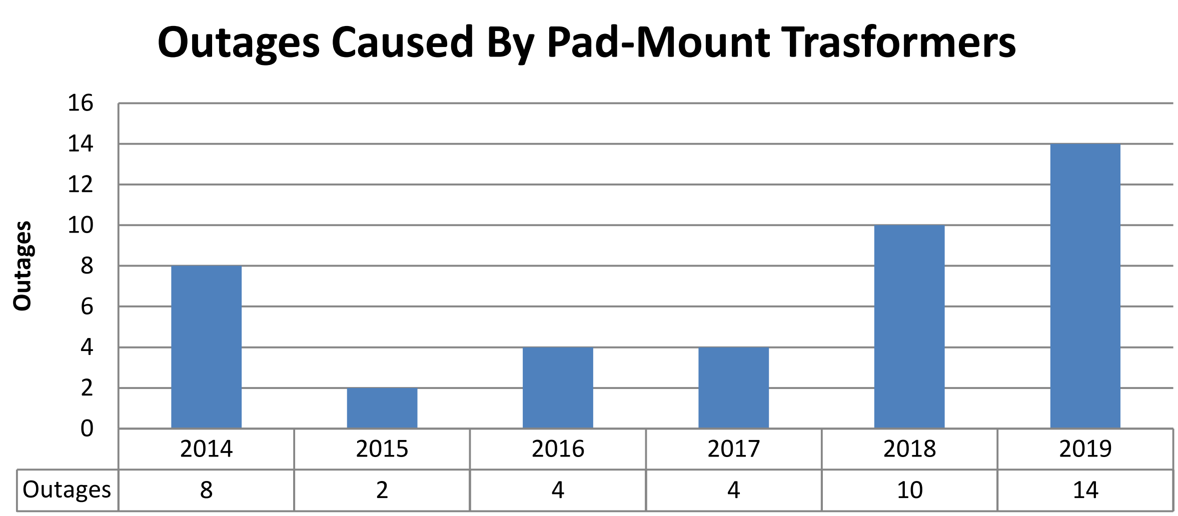
Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver for this investment are the age and condition of the pad mounted transformers. The condition and age of the all of NPEI's pad mount transformers based on the 2018 ACA report is summarized in the tables below:

Age	0 - 10	11 - 20	21 - 30	>30
Condition	Quantity			
Very Good	971	959	1,068	232
Good	4	7	8	49
Fair	7	16	25	9
Poor	-	4	8	2
Very Poor	-	-	-	-

NPEI plans to address approximately 5 Poor condition transformers in 2021. The transformers selected under this program will be chosen based on their Health Index in the 2018 ACA report and NPEI's yearly underground inspection.

The secondary driver for this investment is system reliability. Since 2014, pad transformer failure has directly resulted in approximately 7 outages per year. See Below:



Project Name: Pad-Mounted Transformer Replacement
Category: System Renewal

Good Utility Practice (5.4.3.2.B.1.b)

NPEI has an ongoing yearly program to both inspect all underground equipment, which includes pad mounted distribution transformers. As well, items identified as requiring immediate replacement are addresses as soon as possible. The cycle for underground equipment inspection is as follows:

All underground equipment is inspected once every 3 Years for Urban Areas
All underground equipment is inspected once every 6 Years for Rural Areas

The source of information for the transformer cost is based on historical costs for pad-mount transformers. Proactively replacing these transformers prior to failure will reduce the cost per transformer as the work can be performed during regular business hours avoiding overtime premiums.

Replacement of Pad-mount transformers will be completed in accordance with NPEI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. The transformer will be replaced with NPEI's current standard for Pad-mount transformers used throughout the NPEI system.

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is medium, this program ranked 16 out of 24 projects in our Project Priority Matrix for 2021. NPEI views System Renewal projects as a lower priority than System Access projects, unless the condition of the assets poses an immediately risk to system stability and/or public safety. Within System Renewal projects this projects ranks as medium priority as this is a new program, as traditionally these assets were run until failure.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Planned replacement of assets compared to replacement at failure offers several advantages. The cost per transformer is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By replacing these transformers prior to failure, the costs associated with the replacement are drastically reduced. Further, the risk of an outage caused by failed equipment is greatly reduced and the duration of the outage to make the change is controllable and small.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

A Pad-mount transformer failure can cause prolonged outages and cause damage to surrounding equipment. By replacing these transformers prior to failure, the reliability for the customers serviced by these transformers is improved as it reduces the risk of an equipment failure.

Having a scheduled outage to switch customers to a new transformer will take far less time than changing a transformer that has failed at end of life.

Project Name: Pad-Mounted Transformer Replacement
Category: System Renewal

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Replace Pad Mount transformers upon failure

The only advantage to this option is up front cost savings which pales in comparison to the disadvantages. Overall total costs would be significantly higher as assets would be replaced on an emergency basis. Total quantity of outages would increase due to equipment failures and public safety would be put at risk.

Scheduling Alternatives:

As this program is a lower priority compared to other projects, the schedule as to when these jobs are complete can be flexible. However, as end of life asset replacement is deferred, there is an increased risk to public safety and system reliability decreases.

Ownership Alternatives:

This program consists solely of NPEI assets. However, in cases where a customer is looking to upgrade their service to use a transformer larger than 1500 kVA, it would be the responsibility of the customer to take ownership of their own transformer.

Safety (5.4.3.2.B.2)

Replacement of Pad-mount transformers will be completed in accordance with NPEI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. The transformer will be replaced with NPEI's current standard for Pad Mount transformers used throughout the NPEI system.

Cyber-Security and Privacy (5.4.3.2.B.3)

Not applicable

Co-ordination and Interoperability - **Co-ordination with utilities, regional planning and/or links with 3rd parties** (5.4.3.2.B.4.a)

This program will be coordinated with the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln, the Town of Pelham, the Niagara Region, Bell Canada, Rogers, Cogeco and NRBN. As well there will be coordination with the customer(s) affected by the transformer replacement.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

Not Applicable.

Environmental Benefits (5.4.3.2.B.2.B.5)

As the transformers that will be replaced in this program are typically older in age, they are at an increased risk for failure. In some cases these older transformers may be prone to oil leaks, which can be harmful to the environment. Replacing aging pad-mount transformers proactively would reduce the risk of this environmental hazard.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable

Project Name: Pad-Mounted Transformer Replacement
Category: System Renewal

Category – Specific Requirements – System Renewal (5.4.3.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C – SR.i.a)

The proposed program aims to target assets proactively whose condition has deteriorated to the extent that prudent measures must be taken to safeguard the performance of the system and public welfare

Operational Effectiveness - SAIDI and SAIFI will be improved by proactively replacing transformers before failure occurs
Safety - Replacing end of life pad mount transformers avoids safety issues such as oil leaks.
Customer Focus – Replacing transformers, reduces the likelihood of long duration unplanned outages due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C – SR.i.b)

NPEI has the typical life cycle of these assets as 30 years.

From the ACA report and data shown in section 5.4.3.2.B.1.a, 292 pad mount transformers have surpassed their useful life.

Number of Impacted Customers (5.4.3.2.C – SR.i.c)

Each pad mount transformer can service approximately 10-12 residential customers. Assuming the worst case of 12 customers per transformer and with 5 transformers to be changed, potentially up to 60 customers could be impacted. There are cases where one distribution transformer could service a multiple tenant building such as an apartment building, so even though this may be one customer, many residents are affected by an outage.

Quantitative Customer Impact and Risk (5.4.3.2.C – SR.i.d)

The average outage duration to change a failed pad mount transformer is approximately 4-6 hours. Therefore, if 60 customers are affected by this type of outage, it would equate to 360 customer hours.

Qualitative Customer Impact and Risk (5.4.3.2.C – SR.i.e)

If these transformers are not replaced, the risk of unplanned outages and outage duration will increase resulting in lower customer satisfaction. Pole mount transformers take between 4 and 6 hours to replace.

Value of Customer Impact (5.4.3.2.C – SR.i.f)

Value of customer impact is low. A failure would only result in an outage of 10-12 residential customers or 1-5 commercial customers for the duration of the outage. However, if the failure caused the feeder breaker to open, it could affect 1000’s of customers.

If pad-mount transformers are run until failure, there is a strong likelihood that forced outages will occur resulting in overtime required for response. Pad-mount transformers tend to fail during time of high demand which is usually outside regular business hours for residential customers.

Project Name: Pad-Mounted Transformer Replacement
Category: System Renewal

Factors Affecting Project Timing (5.4.3.2.C – SR.ii)

As this program focuses on planned replacement of assets still in operation, there is flexibility in scheduling. Coordination may be required to replace commercial customers to minimize outage durations and have minimal impact on their business.

Effect on System O&M Costs (5.4.3.2.C – SR.iii)

If pad mount transformers are run until failure, there is a strong likelihood that forced outages will occur resulting in overtime required for response.

By installing new distribution transformers to current NPEI standards, there will be cost savings realized in inventory management as equipment is standardized.

Impact on Reliability and Safety (5.4.3.2.C – SR.iv)

By proactively replacing the end of life transformers, safety issues associated with equipment failures and oil spills are avoided.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C – SR.v)

Alternatives have been discussed in section (5.4.3.2.B.1.d.iii). The benefits to proactively replacing end of life pad-mount transformers are clear – new pad-mount transformers increase safety and system reliability.

Replacing end of life pad-mount transformers will avoid and/or reduce the frequency and duration of power outages. Maintaining the status quo will result in future outages which will lead to lengthy unplanned work and customer dissatisfaction.

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.3.2.C – SR.vi)

Replacement of pad-mount transformers is a like for like replacement. However, as one of the factors causing the equipment to fail is the transformer demand, the loading would be assessed at the time of replacement. If required, the transformer and associated equipment would be upgraded to meet the demand.

Project Sign-Off

Prepared By:	Paul Uguccioni	Authorized By:	
Date:	January 27, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	Pole Replacement Program	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	All

General Information on Project (5.4.3.2.A)

Project Summary	The degradation of utility poles is an ongoing issue. NPEI performs a site visit of every distribution pole on the System as per OEB requirements (3 yrs/urban, 6 yrs/rural), with a total population of over 37,000. The pole is tested for its integrity, a visual inspection is performed of the equipment installed on the pole by qualified Linesmen, the pole is imaged, guy guards are installed & down grounds are repaired/replaced as required, and the inspection results and images are stored within the Geographical Information System (GIS). An evaluation of the results is performed, with deficiencies addressed by the replacement of deficient poles, in a timely manner, through this Capital Program. The average cost per pole change is approximately $ 5,000.
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:** $657,322.52
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** $0.00 **NPEI Estimated Cost:** $657,322.52
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	Customer attachments varies depending on the pole being replaced (i.e. single phase, three phase, or secondary) and location of pole.
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 1, 2021 **In Service Date:** December 31, 2021

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$200,000	$128,661.26	$200,000	$128,661.26

Project Name: Pole Replacement Program
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material

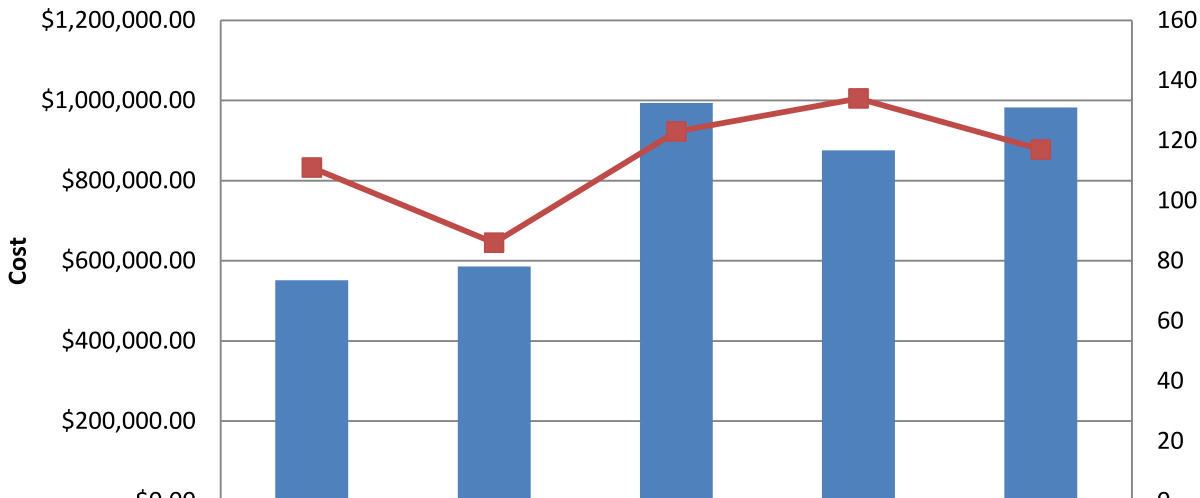
Project Name: Pole Replacement Program
Category: System Renewal

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints. Material risk is mitigated by following NPEI's standard practice of ordering poles on a regular basis and having spares on hand. By having a list of tagged poles for replacement, labour resources can be planned accordingly to tackle poles in a logical and cost effective manner.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

The table below summarizes the pole replacement program from 2015 to 2019. Over this period, the average cost to replace a pole was $6,841.



	2015	2016	2017	2018	2019
Cost	$551,138.53	$585,866.00	$993,276.99	$875,257.45	$982,532.20
Poles	111	86	123	134	117

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not applicable

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable

Project Name: Pole Replacement Program
Category: System Renewal

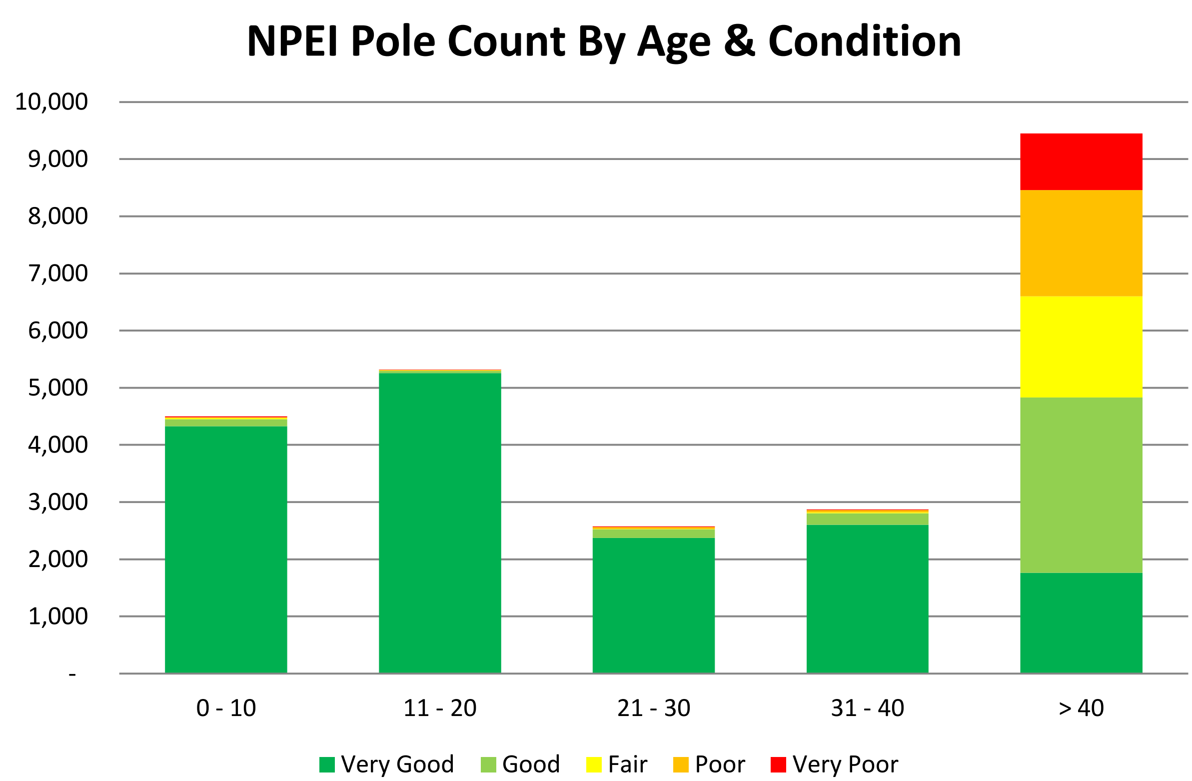
Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver for this investment are the age and condition of poles in our system. The condition and age of the all of NPEI's poles is summarized based on the 2018 ACA report is summarized in the table and graph below:

Poles					
Age	0 - 10	11 - 20	21 - 30	31 - 40	> 40
Condition	Quantity				
Very Good	4,326	5,256	2,374	2,603	1,761
Good	123	41	150	204	3,071
Fair	22	3	6	14	1,766
Poor	14	11	32	38	1,862
Very Poor	17	7	14	14	992



NPEI plans to address approximately 100 "Very Poor" condition poles in 2021. The poles that fall under this program are in addition to poles that would be replaced in area rebuilds. Therefore, more than 100 Very Poor conditions would be addressed in a calendar year. The poles selected under this program are based on their most recent pole inspection result and poles not addressed in other are rebuilds.

Project Name: Pole Replacement Program
Category: System Renewal

The secondary driver for this investment is system reliability. As poles deteriorate over time, they have an increased rate of failure. A planned program for replacement minimizes the risk of overhead line failure and unplanned outages.

Good Utility Practice (5.4.3.2.B.1.b)

NPEI has an ongoing yearly program to both inspect and replace poles previously identified as needing replacement. The cycle for inspection is as follows:

All Poles are inspected Once every 3 Years for Urban Areas
All Poles are inspected Once every 6 Years for Rural Areas

A summary of the pole inspections in recent years is summarized below:

Year	Replace 1-5	Replace Immediately	Total Inspected
2014	86	75	6362
2015	96	54	7980
2016	108	53	7314
2017	111	17	6705
2018	102	32	4519
2019	49	30	6508

Proactively replacing these poles prior to failure will reduce the cost per pole as the work can be performed during regular business hours avoiding overtime premiums.

Replacement of poles will be completed in accordance with NPEI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. As many of the poles replaced are older in age, the new poles will be installed to NPEI's current standards.

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is Low, this program ranked 18 out 24 projects in our Project Priority Matrix for 2021. NPEI views System Renewal projects as a lower priority than System Access projects, unless the condition of the assets poses an immediately risk to system stability and/or public safety. Within System Renewal projects this projects ranks as low priority as poles replacements are also addressed during complete area rebuilds.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Planned replacement of assets compared to replacement at failure offers several advantages. The cost per pole is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By replacing these poles prior to failure, the costs associated with the replacement are drastically reduced. Further, the risks associated with pole failure and possible downed power lines are greatly reduced with the installation of new poles and associated hardware with higher structural strength.

Project Name: Pole Replacement Program
Category: System Renewal

Feedback from our Customer Engagement online Workbook indicated that the majority of our customer base across all rate classes would like NPEI to replace poles at the suggested pace or at an accelerated pace. Below is a summary of the results:

Customer Class	Customers that support the suggested pace or accelerated pace
Residential	82% (n = 1,264)
Small Business	87% (n = 56)
Mid-Sized Business	25 of 32

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

A Pole failure can cause prolonged outages and cause damage to surrounding equipment. By replacing these poles prior to failure, the reliability for the customers serviced by these poles is improved as it reduces the risk of an equipment failure.

In many cases a planned Pole Replacement does not require an outage or it allows for a scheduled outage which will take far less time than changing a pole that has failed at end of life.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Replace Poles upon failure

The only advantage to this option is up front cost savings which pales in comparison to the disadvantages. Overall total costs would be significantly higher as assets would be replaced on an emergency basis. Total quantity of outages would increase due to equipment failures and public safety would be put at risk.

Replace Poles as part of Area Rebuilds

This approach is preferred and done when possible. However, the number of poles that need attention, exceeds the budget amount for this type of work. Also, there are many locations where every pole within an area is in poor condition. The risk is too high to leave poles that are identified in our yearly inspections as flagged “Replace Immediately” until an area rebuild occurs.

Scheduling Alternatives:

As this program is a lower priority compared to other projects, the schedule as to when these jobs are complete can be flexible. However, as end of life asset replacement is deferred, there is an increased risk to public safety and system reliability decreases.

Ownership Alternatives:

None. This program consists solely of NPEI assets and is constructed in the public right-of-way.

Project Name: Pole Replacement Program
Category: System Renewal

Safety (5.4.3.2.B.2)

Replacement of poles that are at the end of their useful life and in poor condition will reduce the likelihood of unexpected pole failures and possible downed wires. Having downed primary wires on the ground creates a safety hazard for the public and workers.

Replacement of poles will be completed in accordance with NPEI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. As many of the poles replaced are older in age, the new poles will be installed to NPEI's current standards.

Cyber-Security and Privacy (5.4.3.2.B.3)

Not Applicable

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This program will be coordinated with the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln, the Town of Pelham, the Niagara Region for their planned road work. There will be coordination with Bell Canada, Rogers, Cogeco and NRBN for their joint use attachments. As well there will be coordination with the customer(s) if they are affected by the pole replacement.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

Not applicable

Environmental Benefits (5.4.3.2.B.2.B.5)

Many of the poles to be replaced are older in age and were likely treated with pentachlorophenol, although a great preservative PCP is classified as a probable human carcinogen. Removing and replacing these poles will ensure that no more pentachlorophenol leeches into the soil and ultimately our water supply.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable

Category – Specific Requirements – System Renewal (5.4.3.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C – SR.i.a)

The proposed program aims to target assets proactively whose condition has deteriorated to the extent that prudent measures must be taken to safeguard the performance of the system and public welfare

Operational Effectiveness - SAIDI and SAIFI will be improved by proactively replacing poles before failure occurs
Safety - Replacing end of life poles avoids safety issues such as downed power lines.
Customer Focus – Replacing poles, reduces the likelihood of long duration unplanned outages due to equipment failure.

Project Name: Pole Replacement Program
Category: System Renewal

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C – SR.i.b)
The typical life cycle of these assets is 40 years. From the ACA report and data shown in section 5.4.3.2.B.1.a, XXX poles have surpassed their useful life.
Number of Impacted Customers (5.4.3.2.C – SR.i.c)
The exact number of customers impacted is unknown until a detailed design is completed.
Quantitative Customer Impact and Risk (5.4.3.2.C – SR.i.d)
Typically 1-6 customers are directed impacted by a single pole failure. However, if the failure caused the feeder breaker to open, it could affect 1000's of customers.
Qualitative Customer Impact and Risk (5.4.3.2.C – SR.i.e)
If these poles are not replaced, the risk of unplanned outages and outage duration will increase resulting in lower customer satisfaction. On average, emergency pole replacements take between 6 and 8 hours.
Value of Customer Impact (5.4.3.2.C – SR.i.f)
Value of customer impact is medium. A failure would only result in an outage of a small number of residential and/or commercial customers for the duration of the outage. However, if the failure caused the feeder breaker to open, it could affect 1000's of customers. If poles remain until failure, there is a strong likelihood that forced outages will occur resulting in overtime required for response.
Factors Affecting Project Timing (5.4.3.2.C – SR.ii)
As this program focuses on planned replacement of assets still in operation, there is flexibility in scheduling. Coordination may be required with the local road authorities and/or any customers affected by the pole replacement.
Effect on System O&M Costs (5.4.3.2.C – SR.iii)
If a pole remains in service until failure, there is a strong likelihood that forced outages will occur resulting in overtime required for response. Replacing the assets and other attachments on the pole with NPEI's current design and hardware will also reduce the cost of future repairs that may arise from potential pole failures.
Impact on Reliability and Safety (5.4.3.2.C – SR.iv)
By proactively replacing the end of life poles, safety issues associated with equipment failures and possible downed power lines are avoided.
Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C – SR.v)
Alternatives have been discussed in section (5.4.3.2.B.1.d.iii). The benefits to proactively replacing end of life poles are clear – new poles increase safety and system reliability. Replacing end of life poles will avoid and/or reduce the frequency and duration of power outages. Maintaining the status quo will result in future outages which will lead to lengthy unplanned work and customer dissatisfaction.

Project Name: Pole Replacement Program
Category: System Renewal

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.3.2.C – SR.vi)
Replacement of poles under this program is considered a like for like replacement. Although new pole installation will be done in accordance to NPEI's current design and material standards, they will remain as distribution poles serving the same function they do presently.

Project Sign-Off			
Prepared By:	Paul Uguccioni	Authorized By:	
Date:	January 27, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	Pole Mounted Transformer Replacement	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	All

General Information on Project (5.4.3.2.A)

Project Summary	Project scope involves the replacement of aged pole mount transformers, identified in NPRI's asset management system of having a very poor or poor health index. NPEI's target is to replace 50 units per year. Benefits of the program include increased system reliability and Public & Personnel safety.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:** $410,463.08			
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** $0.00 **NPEI Estimated Cost:** $410,463.08			
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	Pole mounted transformers range in size from 15kVA – 167kVA. NPEI's target is 50 units per year. The customers can range from 1 large commercial to approximately 12-15 residential customers per pole mount transformer.			
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 1, 2021 **In Service Date:** December 31, 2021			
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$200,000	$40,000	$150,000	$20,463.08

Project Name: Pole-Mounted Transformer Replacement
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material

Project Name: Pole-Mounted Transformer Replacement
Category: System Renewal

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints. Manufacturers require 16-20 weeks for delivery for each unit pole mount transformer. Material risk is mitigated by following NPEI's standard practice of ordering transformers on a regular basis and having spares on hand. By having a list of tagged transformers for replacement, labour resources can be planned accordingly to tackle transformers in a logical and cost effective manner.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

The pole mount transformer replacement program is new to NPEI, so information from equivalent projects does not exist at this time. By examining historical data, the average cost to replace a pole mount transformer is $8,206.26.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not applicable

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

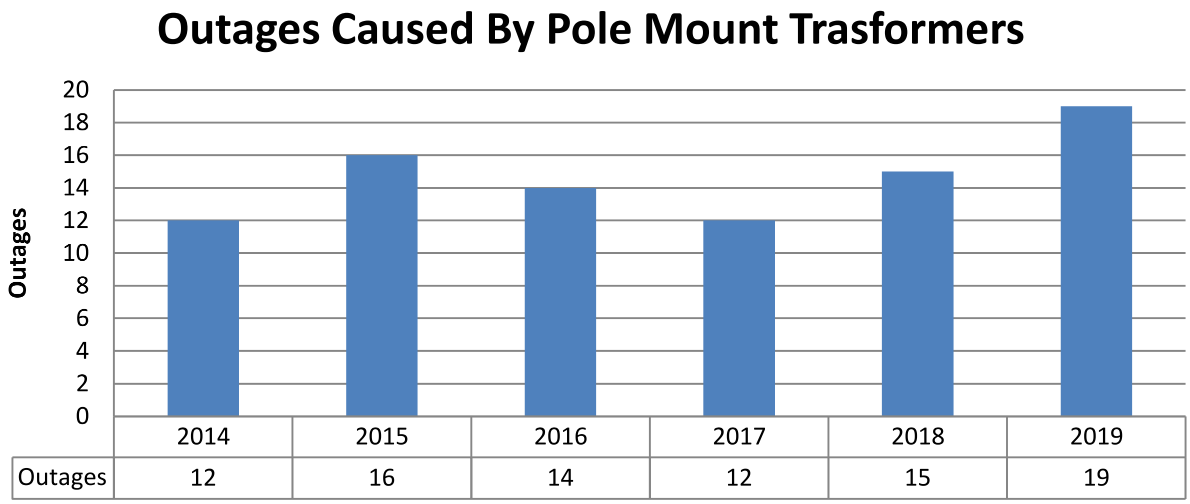
The primary driver for this investment are the age and condition of the pole mounted transformers. The condition and age of the all of NPEI's pole mount transformers based on the 2018 ACA report is summarized in the tables below:

Transformers					
Age	0 - 10	11 - 20	21 - 30	31 - 40	> 40
Condition	Quantity				
Very Good	1,856	1,093	154	-	-
Good	9	16	841	-	-
Fair	10	6	188	627	-
Poor	6	8	9	213	338
Very Poor	11	27	18	8	613

NPEI plans to address approximately 50 Very Poor condition transformers in 2021. The transformers that fall under this program are in addition to transformers that would be replaced in area rebuilds. Therefore, more than 50 Very Poor conditions would be addressed in a calendar year. The transformers selected under this program will be chosen based on their Health Index in the 2018 ACA report and not addressed in other are rebuilds.

The secondary driver for this investment is system reliability. Since 2014, pole mount transformer failure has directly resulted in approximately 15 outages per year. See Below:

Project Name: Pole-Mounted Transformer Replacement
Category: System Renewal



Good Utility Practice (5.4.3.2.B.1.b)

The source of information for the transformer cost is based on historical costs for pole mount transformers. Proactively replacing these transformers prior to failure will reduce the cost per transformer as the work can be performed during regular business hours avoiding overtime premiums.

Replacement of Pole mount transformers will be completed in accordance with NPEI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. The transformer will be replaced with NPEI's current standard for Pole Mount transformers used throughout the NPEI system.

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is medium, this program ranked 15 out 24 projects in our Project Priority Matrix for 2021. NPEI views System Renewal projects as a lower priority than System Access projects, unless the condition of the assets poses an immediately risk to system stability and/or public safety. Within System Renewal projects this projects ranks as medium priority as traditionally this Pole Mount transformers are addressed during complete area rebuilds.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Planned replacement of assets compared to replacement at failure offers several advantages. The cost per transformer is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By replacing these transformers prior to failure, the costs associated with the replacement are drastically reduced. Further, the risk of an outage caused by failed equipment is greatly reduced and the duration of the outage to make the change is controllable and small.

Project Name: Pole-Mounted Transformer Replacement
Category: System Renewal

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)
A Pole Mount transformer failure can cause prolonged outages and cause damage to surrounding equipment. By replacing these transformers prior to failure, the reliability for the customers serviced by these transformers is improved as it reduces the risk of an equipment failure. Having a scheduled outage to switch customers to a new transformer will take far less time than changing a transformer that has failed at end of life.
Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)
Project Design Alternatives: Replace Pole Mount transformers upon failure The only advantage to this option is up front cost savings which pales in comparison to the disadvantages. Overall total costs would be significantly higher as assets would be replaced on an emergency basis. Total quantity of outages would increase due to equipment failures and public safety would be put at risk. Scheduling Alternatives: As this program is a lower priority compared to other projects, the schedule as to when these jobs are complete can be flexible. However, as end of life asset replacement is deferred, there is an increased risk to public safety and system reliability decreases. Ownership Alternatives: None. This program consists solely of NPEI assets.
Safety (5.4.3.2.B.2)
Replacement of Pole mount transformers will be completed in accordance with NPEI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. The transformer will be replaced with NPEI's current standard for Pole Mount transformers used throughout the NPEI system.
Cyber-Security and Privacy (5.4.3.2.B.3)
Not applicable.
Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)
This program will be coordinated with the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln, the Town of Pelham, the Niagara Region, Bell Canada, Rogers, Cogeco and NRBN. As well as coordination with the customers affected by the transformer replacement.
Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)
Not applicable.

Project Name: Pole-Mounted Transformer Replacement
Category: System Renewal

Environmental Benefits (5.4.3.2.B.2.B.5)

As the transformers that will be replaced in this program are typically older in age, they are at an increased risk for failure. In some cases these older transformers may be prone to oil leaks, which can be harmful to the environment. Replacing aging pole mount transformers proactively would reduce the risk of this environmental hazard.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Category – Specific Requirements – System Renewal (5.4.3.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C – SR.i.a)

The proposed program aims to target assets proactively whose condition has deteriorated to the extent that prudent measures must be taken to safeguard the performance of the system and public welfare

Operational Effectiveness - SAIDI and SAIFI will be improved by proactively replacing transformers before failure occurs
Safety - Replacing end of life pole mount transformers avoids safety issues such as pole fires.
Customer Focus – Replacing transformers reduces the likelihood of long duration, unplanned outages due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C – SR.i.b)

The typical life cycle of these assets is 40 years.

From the ACA report and data shown in section 5.4.3.2.B.1.a, 951 pole mount transformers have surpassed their useful life.

Number of Impacted Customers (5.4.3.2.C – SR.i.c)

Each pole mount transformer can service approximately 12-15 residential customers. Assuming the worst case of 15 customers per transformer and with 50 transformers to be changed, up to 750 customers could be impacted.

Quantitative Customer Impact and Risk (5.4.3.2.C – SR.i.d)

The average outage duration to change a failed pole mount transformer is approximately 4 hours. Therefore, if 600 customers are affected by this type of outage, it would equate to 2,400 customer hours.

Qualitative Customer Impact and Risk (5.4.3.2.C – SR.i.e)

If these transformers are not replaced, the risk of unplanned outages and outage duration will increase resulting in lower customer satisfaction. Pole mount transformers take between 3 to 4 hours to replace.

Project Name: Pole-Mounted Transformer Replacement
Category: System Renewal

Value of Customer Impact (5.4.3.2.C – SR.i.f)

The value of customer impact is low. A failure would impact 12-15 residential customers or 1-5 commercial customers for the duration of the outage. However, if the failure caused the feeder breaker to open, it could affect thousands of customers.

If pole mount transformers are run until failure, there is a strong likelihood that forced outages will occur resulting in overtime required for response. Pole mount transformers tend to fail during times of high demand which is usually outside regular business hours for residential customers.

Factors Affecting Project Timing (5.4.3.2.C – SR.ii)

As this program focuses on planned replacement of assets still in operation, there is flexibility in scheduling. Coordination may be required to replace commercial customers to minimize outage durations and have minimal impact on their business.

Effect on System O&M Costs (5.4.3.2.C – SR.iii)

If pole mount transformers are run until failure, there is a strong likelihood that forced outages will occur resulting in overtime required for response. Pole mount transformers tend to fail during times of high demand which is usually outside regular business hours for residential customers.

Impact on Reliability and Safety (5.4.3.2.C – SR.iv)

By proactively replacing the end of life transformers, safety issues associated with equipment failures and oil spills are avoided.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.3.2.C – SR.v)

Alternatives have been discussed in section (5.4.3.2.B.1.d.iii). The benefits to proactively replacing end of life pole mount transformers are clear – new pole mount transformers increase safety and system reliability.

Replacing end of life pole mount transformers will avoid and/or reduce the frequency and duration of power outages. Maintaining the status quo will result in future outages which will lead to lengthy unplanned work and customer dissatisfaction.

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.3.2.C – SR.vi)

Replacement of pole mount transformers is a like for like replacement. However, as one of the factors causing the equipment to fail is the transformer demand, the loading would be assessed at the time of replacement. If required, the transformer and associated equipment would be upgraded to meet the demand.

Project Sign-Off

Prepared By:	Paul Uguccioni	Authorized By:	
Date:	January 27, 2020	Date:	
		Completion Date:	

Capital Project Summary

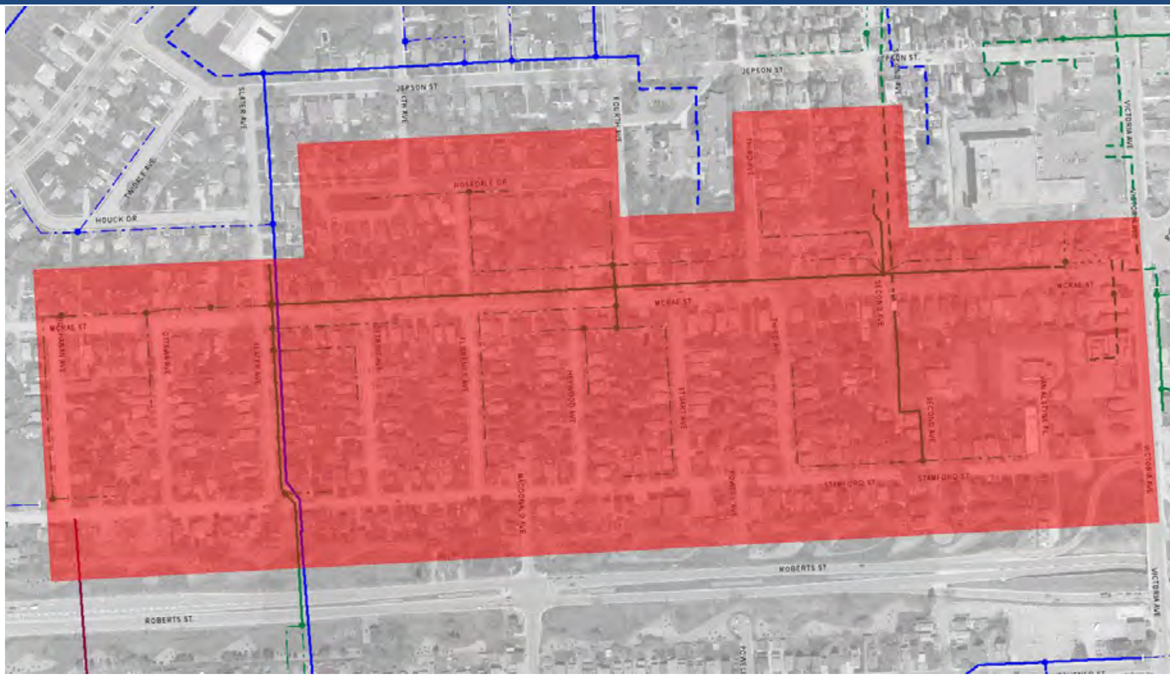
Project Name:	Prospect, Brittania, Kitchener Area - Voltage Conversion	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	Niagara Falls

General Information on Project (5.4.4.2.A)

Project Summary	Rebuild single phase 2.4 kV circuit currently being supplied by step-down transformer #6790 and connect the load directly to the 13.8 kV system. To facilitate connection to the 13.8 kV system, Brittania Cr, Kitchener St and Prospect St must be rebuilt to 13.8 kV standards, including tree wire and 40' poles. Rebuild benefits include improved system losses, improved equipment clearances, reinforcement and capacity increase of the supply in the area.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$362,010.66		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	$0.00		
	NPEI Estimated Cost:	$362,010.66		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	105 customers / 315 kVA (assuming 3 kVA per customer)			
Project Dates (5.4.3.2.A.iv)	**Start Date:**	February 1, 2021		
	In Service Date:	August 31, 2021		
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$81,005.33	$200,000	$81,005.33	$0

Project Name: Prospect, Brittania, Kitchener Area - Voltage Conversion
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material



Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints, approvals from applicable authorities and coordination with third parties. Risk mitigation is accomplished by completing the design 4-6 months in advance of construction and project scheduling in conjunction with Operations and Stores, coordinating with the road authority and third parties through the Public Utilities Coordinating Committee (PUCC).

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

In 2019, a similar project was completed in the Niagara Falls area of McLeod Road and Drummond Road. This project was Phase 3 of a multi-phase system rebuild/voltage conversion and included replacement of 76 poles and 250 customers. The total cost this phase was $828,037.52 (approx. $10,895.23 per pole and $3,312.15 per customer).

Approximately 35 poles will be replaced and 105 customers will be affected under this project which equates to $10,343.16 per pole and $3,447.72 per customer.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Project Name: Prospect, Brittania, Kitchener Area - Voltage Conversion
Category: System Renewal

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver of this project is the age and condition of the existing pole line. The condition and age of the affected poles and transformers is summarized in the tables below.

Poles						
Age	0 - 10	11 - 20	21 - 30	31 - 40	41-50	> 50
Condition	Quantity					
Very Good	5	3	4	2	2	4
Good	-	-	-	1	2	10
Fair	-	-	-	-	-	2
Poor	-	-	-	-	-	-
Very Poor	-	-	-	-	-	-

Transformers					
Age	0 - 10	11 - 20	21 - 30	31 - 40	> 40
Condition	Quantity				
Very Good	-	-	-	-	-
Good	-	-	-	-	-
Fair	-	-	-	1	-
Poor	-	-	-	-	-
Very Poor	-	-	-	-	3

Secondary driver is voltage conversion. The existing line is single phase 2.4 kV, the new line will be single phase 8 kV. Standardizing the voltage across the city offers tremendous benefit in terms equipment standardization, lower system losses, increased clearances and overall safety.

Good Utility Practice (5.4.3.2.B.1.b)

The project was selected by historical knowledge and expertise of our system, which was verified by overlaying the health index of our assets in to our GIS system. With this information a heat map was generated giving a visual representation of areas requiring attention in our system.

As part of our standard engineering practices, pole lines are designed and built to meet or exceed the latest revision of CSA C22.3 No.1. Overhead Systems, which ensures that new distribution system expansions, extensions and replacement are constructed to a level appropriate with the regional climate.

Project Name: Prospect, Brittania, Kitchener Area - Voltage Conversion
Category: System Renewal

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is medium, this program ranked 11 out of 24 projects in our Project Priority Matrix for 2021. NPEI views System Renewal projects as a lower priority than System Access projects, unless the condition of the assets poses an immediately risk to system stability and/or public safety. Within System Renewal projects this projects ranks as medium priority as it has been deferred from previous years.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Planned replacement of assets compared to replacement at failure offers several advantages. The cost per pole is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums. Proactive replacement allows the entire line to be redesigned and in this case a voltage conversion.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line customers will experience improved reliability, the voltage conversion will provide greater flexibility and improve restoration times during outages. The risks associated with downed power lines will be drastically reduced with the installation of new poles, wires and associated hardware.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Rebuilding the pole line will greatly increase reliability as many of the assets are near or at end of life. The voltage conversion will reduce overall system losses and decrease frequency and duration of outages due to equipment failure.

The subdivision is currently supplied by a single 13.8 kV / 4.16 kV step down transformers on the 3M51 circuit. The voltage conversion will allow for two additional ties to the 3M52 & 3M14 which will provide greater flexibility and improve restoration times during outages.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Replace end of life assets
This option would replace only the assets identified as end of life. Voltage conversion would be a lost opportunity meaning system losses would not be reduced and system stability would not be increased. The work would be done piece by piece which would require ongoing maintenance to address issues with aging assets as they arise.

Replace assets upon failure
The only advantage to this option is up front cost savings which pales in comparison to the disadvantages. Overall total costs would be significantly higher as assets would be replaced on an emergency basis. Total quantity of outages would increase due to equipment failures and public safety would be put at risk. Voltage conversion opportunity would be lost.

Scheduling Alternatives:

In the event an unplanned job arises with a higher priority, the schedule can be revised to accommodate. However, as end of life asset replacement is deferred, there is an increased risk to public safety and system reliability decreases.

Project Name: Prospect, Brittania, Kitchener Area - Voltage Conversion
Category: System Renewal

Ownership Alternatives:

None. This project consists of NPEI assets and is constructed on the public right of way.

Safety (5.4.3.2.B.2)

The pole line rebuild is designed and constructed in accordance with NPEIs standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Prior to energization, all worked is inspected and signed off by NPEI.

Replacement of deteriorated poles, wires and vintage transformers drastically reduces the likelihood of catastrophic failure, resulting in possible downed wires. Downed wires pose the greatest risk to public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3)

Not applicable.

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This project will be coordinated with the City of Niagara Falls, Bell Canada, Rogers and NRBN and road authority, where applicable. As well there will be coordination with the customers affected by this rebuild project.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The pole line rebuild will facilitate more load transfer capability of NPEI’s distribution system.

Environmental Benefits (5.4.3.2.B.2.B.5)

Voltage conversion reduces system losses, ultimately requiring fewer resources. Depending on the current supply mix, this is beneficial for the environment.

Many of the poles to be replaced were treated with pentachlorophenol, although a great preservative PCP is classified as a probable human carcinogen. Removing and replacing these poles will ensure that no more pentachlorophenol leeches into the soil and ultimately our water supply.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Category – Specific Requirements – System Renewal (5.4.4.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.4.2.C – SR.i.a)

The proposed project aims to target assets proactively whose condition has deteriorated to the extent that prudent measures must be taken to safeguard the performance of the system and public welfare

Operational Effectiveness - SAIDI and SAIFI will be improved by proactively replacing poles and transformers before failure occurs
Safety - Replacing end of life poles avoids safety issues such as live wire down due to pole failure.
Customer Focus - Replacing poles and transformers, as well as voltage conversion, reduces the likelihood of long duration unplanned outages due to equipment failure.

Project Name: Prospect, Brittania, Kitchener Area - Voltage Conversion
Category: System Renewal

In structuring the pole replacement strategy for 2021, NPEI reviewed the prioritized list of pole integrity deficiencies resulting from cyclical inspections. Areas with a high concentration of pole deficiencies are identified as targets for wholesale system renewal rather than individual change-outs. The decision to perform a wholesale rebuild is deemed to be more efficient when the area encompasses distribution transformers also at or near end of life and where system capacity and loss reduction benefits can also be realized. The balance of prioritized poles is scheduled for change out under the recurring project for pole replacements.

Asset Condition Relative to Typical Life Cycle (5.4.4.2.C – SR.i.b)

This subdivision is comprised of wood poles with pole mounted transformers. The typical useful life of a fully dressed wood pole is 50 years. Approximately 46% of poles are over 50 years old. The typical useful life of a transformer is 40 years, 75% of the transformers are older than 40 years and scored "Very Poor" in the asset condition assessment.

Number of Impacted Customers (5.4.4.2.C – SR.i.c)

105 Residential customers

Quantitative Customer Impact and Risk (5.4.4.2.C – SR.i.d)

As the assets age and risk of failure increases, frequency of interruptions will increase. Duration of interruptions will also increase depending on what time of day the failure occurs.

Although 105 customers are serviced directly by these assets, in the event of an outage it is possible that the feeder breaker for 3M51 opens which would impact 2868 customers.

Qualitative Customer Impact and Risk (5.4.4.2.C – SR.i.e)

As the assets continue to age beyond their life expectancy, outage frequency and duration becomes an increasingly large risk.

Value of Customer Impact (5.4.4.2.C – SR.i.f)

Value of customer impact is medium. A failure would impact 105 residential customers for the duration of the outage. However, if the failure caused the feeder breaker to open, 2868customers would be affected.

Factors Affecting Project Timing (5.4.4.2.C – SR.ii)

The project timing could be impacted by having to re-deploy resources to adjust for unexpected changes in customer demand, such as Road Authority work, subdivision development and commercial connections.

Effect on System O&M Costs (5.4.4.2.C – SR.iii)

The investment to rebuild Prospect-Brittania-Kitchener will improve the reliability of electrical supply by reducing the frequency and duration of electrical outages, caused by aging equipment. This will effectively reduce the O&M costs associated with those outages.

As NPEI continues to convert remaining 4 kV infrastructure to 13.8 kV, O&M savings are realized through reduction carrying costs of materials and furnishing of spare parts.

Project Name: Prospect, Brittania, Kitchener Area - Voltage Conversion
Category: System Renewal

Impact on Reliability and Safety (5.4.4.2.C – SR.iv)

The new pole line is built to current standards, resulting in greater clearances and better safety. Also, replacing end of life assets increases reliability and avoids safety issues due to failing poles and transformers.

The area surrounding the project has already been converted to 13.8 kV, leaving these remaining 105 customers serviced by a single step down transformer. Performing a voltage conversion allows for the elimination of this critical transformer, ultimately increasing reliability for these customers.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.4.2.C – SR.v)

Alternatives have been discussed in section (5.4.3.2.B.1.d.iii). As demonstrated by NPEIs asset condition assessment, this section of line is at the point of needing a rebuild. There are also other areas of NPEIs service territory that are in similar condition and due for a rebuild. The benefits of the rebuild are clear - the voltage conversion increases reliability, building to new standards increases clearances and safety, replacing end of life equipment also increases safety and reliability.

Rebuilding the pole line will avoid and/or reduce power outages. Maintaining the status quo will result in future outages which will lead to unplanned work and customer dissatisfaction.

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.4.2.C – SR.vi)

Replacing the existing infrastructure like for like is a wasted opportunity. The area of this project is surrounded by 13.8 kV, and special provisions are in place to service this area. Eliminating the 4 kV infrastructure is a secondary driver of this project and if not done during this rebuild, it will be done at some time in the future at a much higher overall cost.

Project Sign-Off

Prepared By:	Paul Uguccioni	Authorized By:	
Date:	January 30, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	Regional Road 14 (Sixteen Rd. to Twenty Rd.) - Rebuild	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	West Lincoln

General Information on Project (5.4.4.2.A)

Project Summary	Project scope involves rebuild of a single 3 phase 8.32 kV circuit along Regional Road #14 (built in the 1960s) from Sixteen to Twenty Road. This section of line was identified through NPEI's asset management program as having a low health index score. Construction involves installation of approximately 26 new 45' poles, 3 new single phase transformers, and reuse of remaining transformers. Benefits include replacement of aging equipment, improved equipment clearance and increased customer reliability.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:** $547,178.48			
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** $0.00 **NPEI Estimated Cost:** $547,178.48			
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	14 customers – 12 Residential (42 kVA, assuming 3 kVA), 2 Commercial (200 kVA) Approximately 242 kVA			
Project Dates (5.4.3.2.A.iv)	**Start Date:** April 1, 2021 **In Service Date:** December 1, 2021			
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	$147.178.48	$200,000	$200,000

Project Name: Regional Road 14 (Sixteen Rd. to Twenty Rd.) - Rebuild
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints, approvals from applicable authorities and coordination with third parties. Risk mitigation is accomplished by completing the design 4-6 months in advance of construction and project scheduling in conjunction with Operations and Stores, coordinating with the road authority and third parties through the Public Utilities Coordinating Committee (PUCC).

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

In 2016/17 a similar project was completed in the Niagara Falls area which consisted of rebuilding 1kM of distribution system along Dorchester Road between McLeod and Dunn Street. 26 poles were replaced and the total cost of the project was $607,388.56 (approx. $23,361.10 per pole).

Approximately 26 poles will be replaced this project which equates to $21,045.33.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Project Name: Regional Road 14 (Sixteen Rd. to Twenty Rd.) - Rebuild
Category: System Renewal

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver of this project is the age and condition of the existing pole line. The condition and age of the affected poles and transformers is summarized in the tables below.

Poles						
Age	0 - 10	11 - 20	21 - 30	31 - 40	41-50	> 50
Condition	Quantity					
Very Good	3	-	-	-	1	-
Good	-	-	-	-	3	17
Fair	-	-	-	-	-	1
Poor	-	-	-	-	-	-
Very Poor	-	-	-	-	-	1

Transformers					
Age	0 - 10	11 - 20	21 - 30	31 - 40	> 40
Condition	Quantity				
Very Good	6	-	-	-	-
Good	-	-	2	-	-
Fair	-	-	-	1	-
Poor	-	-	-	1	-
Very Poor	-	-	-	-	1

Good Utility Practice (5.4.3.2.B.1.b)

The project was selected by historical knowledge and expertise of our system, which was verified by overlaying the health index of our assets in to our GIS system. With this information a heat map was generated giving a visual representation of areas requiring attention in our system.

As part of our standard engineering practices, pole lines are designed and built to meet or exceed the latest revision of CSA C22.3 No.1. Overhead Systems, which ensures that new distribution system expansions, extensions and replacement are constructed to a level appropriate with the regional climate.

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is medium, this program ranked 14 out of 24 projects in our Project Priority Matrix for 2021. NPEI views System Renewal projects as a lower priority than System Access projects, unless the condition of the assets poses an immediately risk to system stability and/or public safety. Within System Renewal projects this projects ranks as low priority as the direct number of customers affected by this project is low.

Project Name: Regional Road 14 (Sixteen Rd. to Twenty Rd.) - Rebuild
Category: System Renewal

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)
Planned replacement of assets compared to replacement at failure offers several advantages. The cost per pole is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums. Proactive replacement allows the entire line to be redesigned and in this case a voltage conversion.
Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)
By rebuilding the pole line customers will experience improved reliability. The risks associated with downed power lines will be drastically reduced with the installation of new poles, wires and associated hardware.
Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)
Rebuilding the pole line will greatly increase reliability as many of the assets are near or at end of life. The risks associated with downed power lines will be reduced with the installation of new poles, wires and associated hardware.
Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)
Project Design Alternatives: Replace poles and transformers as they fail Replacing assets as they fail ends up costing more overall as work needs to be completed on an emergency basis. This also leads to a higher number of outages which are longer in duration. The customers are left with a mix of new and old infrastructure that is no more reliable than the existing. Scheduling Alternatives: In the event an unplanned job arises with a higher priority, the schedule can be revised to accommodate. However, as end of life asset replacement is deferred, there is an increased risk to public safety and system reliability decreases. Ownership Alternatives: None. This project consists of NPEI assets and is constructed on the public right of way.
Safety (5.4.3.2.B.2)
The pole line rebuild is designed and constructed in accordance with NPEIs standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Prior to energization, all worked is inspected and signed off by NPEI. Replacement of deteriorated poles, wires and vintage transformers drastically reduces the likelihood of catastrophic failure, resulting in possible downed wires. Downed wires pose the greatest risk to public and workers.
Cyber-Security and Privacy (5.4.3.2.B.3)
Not Applicable

Project Name: Regional Road 14 (Sixteen Rd. to Twenty Rd.) - Rebuild
Category: System Renewal

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This project will be coordinated with the Township of West Lincoln, Bell Canada, Rogers and NRBN and road authority, where applicable. As well there will be coordination with the customers affected by the transformer replacement.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The pole line rebuild will facilitate more load transfer capability of NPEI's distribution system.

Environmental Benefits (5.4.3.2.B.2.B.5)

Many of the poles to be replaced were treated with pentachlorophenol, although a great preservative PCP is classified as a probable human carcinogen. Removing and replacing these poles will ensure that no more pentachlorophenol leeches into the soil and ultimately our water supply.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Category – Specific Requirements – System Renewal (5.4.4.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.4.2.C – SR.i.a)

The proposed project aims to target assets proactively whose condition has deteriorated to the extent that prudent measures must be taken to safeguard the performance of the system and public welfare

Operational Effectiveness - SAIDI and SAIFI will be improved by proactively replacing poles and transformers before failure occurs
Safety - Replacing end of life poles avoids safety issues such as live wire down due to pole failure.
Customer Focus - Replacing poles, transformers and conductors reduces the likelihood of long duration unplanned outages due to equipment failure.

In structuring the pole replacement strategy for 2021, NPEI reviewed the prioritized list of pole integrity deficiencies resulting from cyclical inspections. Areas with a high concentration of pole deficiencies are identified as targets for wholesale system renewal rather than individual change-outs. The decision to perform a wholesale rebuild is deemed to be more efficient when the area encompasses distribution transformers also at or near end of life and where system capacity and loss reduction benefits can also be realized. The balance of prioritized poles is scheduled for change out under the recurring project for pole replacements.

Asset Condition Relative to Typical Life Cycle (5.4.4.2.C – SR.i.b)

This subdivision is comprised of wood poles with pole mounted transformers. The typical useful life of a fully dressed wood pole is 50 years. The majority (73%) of poles are over 50 years old. The typical useful life of a transformer is 40 years, 1 of the transformers are older than 40 years and two others are between 30-40 years old. and only two will be replaced. These are rated as "fair", "poor" and "very poor" and will be replaced while the rest will be reused.

Project Name: Regional Road 14 (Sixteen Rd. to Twenty Rd.) - Rebuild
Category: System Renewal

Number of Impacted Customers (5.4.4.2.C – SR.i.c)

14 customers – 12 Residential & 2 Commercial

Quantitative Customer Impact and Risk (5.4.4.2.C – SR.i.d)

As the assets age and risk of failure increases, frequency of interruptions will increase. Duration of interruptions will also increase depending on what time of day the failure occurs.

Although 14 customers are serviced directly by these assets, in the event of an outage it is possible that the feeder breaker for 1844-F1 opens which would impact 569 customers.

Qualitative Customer Impact and Risk (5.4.4.2.C – SR.i.e)

As the assets continue to age beyond their life expectancy, outage frequency and duration becomes an increasingly large risk.

Value of Customer Impact (5.4.4.2.C – SR.i.f)

Value of customer impact is low. A failure would impact 12 residential customers and 2 commercial customers for the duration of the outage. However, if the failure caused the feeder breaker to open, 569 customers would be affected.

Factors Affecting Project Timing (5.4.4.2.C – SR.ii)

The project timing could be impacted by having to re-deploy resources to adjust for unexpected changes in customer demand, such as Road Authority work, subdivision development and commercial connections.

Effect on System O&M Costs (5.4.4.2.C – SR.iii)

The investment to rebuild this section of Regional Road 14 will improve the reliability of electrical supply by reducing the frequency and duration of electrical outages, caused by aging equipment. This will effectively reduce the O&M costs associated with those outages.

Impact on Reliability and Safety (5.4.4.2.C – SR.iv)

The new pole line is built to current standards, resulting in greater clearances and better safety. Also, replacing end of life assets increases reliability and avoids safety issues due to failing poles and transformers.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.4.2.C – SR.v)

Alternatives have been discussed in section (5.4.3.2.B.1.d.iii). As demonstrated by NPEIs asset condition assessment, this section of line is at the point of needing a rebuild. There are also other areas of NPEIs service territory that are in similar condition and due for a rebuild. The benefits of the rebuild are clear - building to new standards increases clearances and safety and replacing end of life equipment also increases safety and reliability.

Rebuilding the pole line will avoid and/or reduce power outages. Maintaining the status quo will result in future outages which will lead to unplanned work and customer dissatisfaction.

Project Name: Regional Road 14 (Sixteen Rd. to Twenty Rd.) - Rebuild
Category: System Renewal

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.4.2.C – SR.vi)
This project is a like for like replacement. The new line will be built to current standards which means improved pole sizes, hardware and equipment along with greater clearances. It will remain a three phase pole line supplying residential and commercial customers.

Project Sign-Off			
Prepared By:	Paul Ugucccioni	Authorized By:	
Date:	January 31, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	Sixteen Road (Regional Rd. #14 to McCollum Rd.) - Rebuild	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	Lincoln

General Information on Project (5.4.4.2.A)

Project Summary	Project scope involves rebuild of single phase 4.8 kV circuit along Sixteen Road from Regional Road #14 to McCollum Road (built in 1940s). This section of line was identified through NPEI's asset management program as having a low health index score. Construction involves installation of approximately 38 new 40' poles, 1 new single phase transformers, reuse of remaining transformers. Benefits include replacement of aging equipment, improved equipment clearance and increased customer reliability.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$438,623.76		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	$0.00		
	NPEI Estimated Cost:	$438,623.76		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	14 residential customers (42 kVA, assuming 3 kVA per customer)			
Project Dates (5.4.3.2.A.iv)	**Start Date:**	June 1, 2021		
	In Service Date:	November 30, 2021		
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	$100,000	$138,623.76	$200,000

Project Name: Sixteen Road (Regional Rd. #14 to McCollum Rd.) - Rebuild
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints, approvals from applicable authorities and coordination with third parties. Risk mitigation is accomplished by completing the design 4-6 months in advance of construction and project scheduling in conjunction with Operations and Stores, coordinating with the road authority and third parties through the Public Utilities Coordinating Committee (PUCC).

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

In 2016, a similar project was completed in the Jordan area. That project was a multi-phase project. Phase 2 consisted of the replacement of 34 poles and re-use of existing primary conductor. The project cost $424,432.06 (approx. $12,483 per pole).

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

There is no REG investment associated with this project.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Project Name: Sixteen Road (Regional Rd. #14 to McCollum Rd.) - Rebuild
Category: System Renewal

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver of this project is the age and condition of the existing pole line. The condition and age of the affected poles and transformers is summarized in the tables below.

Poles						
Age	0 - 10	11 - 20	21 - 30	31 - 40	41-50	> 50
Condition	Quantity					
Very Good	2	5	9	2	2	-
Good	-	-	-	-	-	10
Fair	-	-	-	-	-	3
Poor	-	-	-	-	-	1
Very Poor	-	-	-	-	-	4

Transformers					
Age	0 - 10	11 - 20	21 - 30	31 - 40	> 40
Condition	Quantity				
Very Good	2	1	-	-	-
Good	-	-	2	-	-
Fair	-	-	-	2	-
Poor	-	-	-	-	-
Very Poor	-	-	-	-	1

This pole line is comprised of wood poles. The typical useful life of a fully dressed wood pole is 50 years. Nearly half of the poles are over 50 years old. The typical useful life of a transformer is 40 years, one existing transformer is over 40 years old and will be replaced.

Good Utility Practice (5.4.3.2.B.1.b)

The project was selected by historical knowledge and expertise of our system, which was verified by overlaying the health index of our assets in to our GIS system. With this information a heat map was generated giving a visual representation of areas requiring attention in our system.

As part of our standard engineering practices, pole lines are designed and built to meet or exceed the latest revision of CSA C22.3 No.1. Overhead Systems, which ensures that new distribution system expansions, extensions and replacement are constructed to a level appropriate with the regional climate.

Project Name: Sixteen Road (Regional Rd. #14 to McCollum Rd.) - Rebuild
Category: System Renewal

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is medium and ranks 13 out of 24 on NPEI's Project Priority Matrix. NPEI views System Renewal projects as a lower priority than System Access projects, unless the condition of the assets poses an immediately risk to system stability and/or public safety. Within System Renewal projects this projects ranks as medium priority as it has been deferred from previous years.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Planned replacement of assets compared to replacement at failure offers several advantages. The cost per pole is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums. Proactive replacement allows the entire line to be redesigned instead of piece by piece.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By rebuilding the pole line customers will experience improved reliability; the increased capacity on the circuit will provide greater flexibility and improve restoration times during outages. The risks associated with downed power lines will be drastically reduced with the installation of new poles, wires and associated hardware.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Rebuilding the pole line will greatly increase reliability as many of the assets are near or at end of life. The increased feeder capacity will reduce overall system losses and decrease frequency and duration of outages due to equipment failure.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Replace end of life assets
This option would replace only the assets identified as end of life. Increasing the size of the primary conductor on the 4.8 kV circuit would be a lost opportunity meaning system losses would not be reduced and system flexibility would not be increased. The work would be done piece by piece which would require ongoing maintenance to address issues with aging assets as they arise.

Replace assets upon failure
The only advantage to this option is up front cost savings which pales in comparison to the disadvantages. Overall total costs would be significantly higher as assets would be replaced on an emergency basis. Total quantity of outages would increase due to equipment failures and public safety would be put at risk. The opportunity to increase the feeder tie capacity would be lost.

Scheduling Alternatives:

In the event an unplanned job arises with a higher priority, the schedule can be revised to accommodate. However, as end of life asset replacement is deferred, there is an increased risk to public safety and system reliability decreases.
Ownership Alternatives:

None. This project consists of NPEI assets and is constructed on the public right of way.

Project Name: Sixteen Road (Regional Rd. #14 to McCollum Rd.) - Rebuild
Category: System Renewal

Safety (5.4.3.2.B.2)

The pole line rebuild is designed and constructed in accordance with NPEIs standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Prior to energization, all worked is inspected and signed off by NPEI.

Replacement of deteriorated poles, wires and vintage transformers drastically reduces the likelihood of catastrophic failure, resulting in possible downed wires. Downed wires pose the greatest risk to public and workers.

Cyber-Security and Privacy (5.4.3.2.B.3)

Not applicable.

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This project will be coordinated with the Town of Lincoln, Bell Canada, Rogers and NRBN and road authority, where applicable. As well there will be coordination with the customers affected by the transformer replacement.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

Not applicable.

Environmental Benefits (5.4.3.2.B.2.B.5)

Many of the poles to be replaced were treated with pentachlorophenol, although a great preservative PCP is classified as a probable human carcinogen. Removing and replacing these poles will ensure that no more pentachlorophenol leeches into the soil and ultimately our water supply.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Category – Specific Requirements – System Renewal (5.4.4.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.4.2.C – SR.i.a)

The proposed project aims to target assets proactively whose condition has deteriorated to the extent that prudent measures must be taken to safeguard the performance of the system and public welfare

Operational Effectiveness - SAIDI and SAIFI will be improved by proactively replacing poles and transformers before failure occurs
Safety - Replacing end of life poles avoids safety issues such as live wire down due to pole failure.
Customer Focus - Replacing poles and transformers, as well as voltage conversion, reduces the likelihood of long duration unplanned outages due to equipment failure.

In structuring the pole replacement strategy for 2021, NPEI reviewed the prioritized list of pole integrity deficiencies resulting from cyclical inspections. Areas with a high concentration of pole deficiencies are identified as targets for wholesale system renewal rather than individual change-outs. The decision to perform a wholesale rebuild is deemed to be more efficient when the area encompasses distribution transformers also at or near end of life and where system capacity and loss reduction benefits can also be realized.

Project Name: Sixteen Road (Regional Rd. #14 to McCollum Rd.) - Rebuild
Category: System Renewal

Asset Condition Relative to Typical Life Cycle (5.4.4.2.C – SR.i.b)

This subdivision is comprised of wood poles with pole mounted transformers. The typical useful life of a fully dressed wood pole is 50 years. Approximately 47% of poles are over 50 years old. The typical useful life of a transformer is 40 years, 1 of the transformers are older than 40 years and only two will be replaced. The rest will be re used.

Number of Impacted Customers (5.4.4.2.C – SR.i.c)

14 residential customers

Quantitative Customer Impact and Risk (5.4.4.2.C – SR.i.d)

As the assets age and risk of failure increases, frequency of interruptions will increase. Duration of interruptions will also increase depending on what time of day the failure occurs.

Although 28 customers are serviced directly by these assets, in the event of an outage it is possible that the feeder breaker for 1844F1 opens which would impact 569 customers.

Qualitative Customer Impact and Risk (5.4.4.2.C – SR.i.e)

As the assets continue to age beyond their life expectancy, outage frequency and duration becomes an increasingly large risk.

Value of Customer Impact (5.4.4.2.C – SR.i.f)

Value of customer impact is low. A failure would impact 14 residential customers for the duration of the outage. However, if the failure caused the feeder breaker to open, 569 customers would be affected.

Factors Affecting Project Timing (5.4.4.2.C – SR.ii)

The project timing could be impacted by having to re-deploy resources to adjust for unexpected changes in customer demand, such as Road Authority work, subdivision development and commercial connections.

Effect on System O&M Costs (5.4.4.2.C – SR.iii)

The investment to rebuild Sixteen Road will improve the reliability of electrical supply by reducing the frequency and duration of electrical outages, caused by aging equipment. This will effectively reduce the O&M costs associated with those outages.

Impact on Reliability and Safety (5.4.4.2.C – SR.iv)

The new pole line is built to current standards, resulting in greater clearances and better safety. Also, replacing end of life assets increases reliability and avoids safety issues due to failing poles and transformers. Increasing the size of the primary conductor to current standards will make the system more reliable as a whole.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.4.2.C – SR.v)

Alternatives have been discussed in section (5.4.3.2.B.1.d.iii). As demonstrated by NPEIs asset condition assessment, this section of line is at the point of needing a rebuild. There are also other areas of NPEIs service territory that are in similar condition and due for a rebuild. The benefits of the rebuild are clear - building to new standards increases clearances and safety and replacing end of life equipment also increases safety and reliability.

Rebuilding the pole line will avoid and/or reduce power outages. Maintaining the status quo will result in future outages which will lead to unplanned work and customer dissatisfaction.

Project Name: Sixteen Road (Regional Rd. #14 to McCollum Rd.) - Rebuild
Category: System Renewal

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.4.2.C – SR.vi)			
Replacing the existing infrastructure like for like forgoes the opportunity to increase the capacity of the circuit to current standards. When this line poses a constraint issue in the future, the cost to re-conductor the line would be significantly higher than the cost to complete the work during this rebuild project.			
Project Sign-Off			
Prepared By:	Weston Sagle	Authorized By:	
Date:	January 30, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	Subdivision Rehab Phase 3	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	Niagara Falls

General Information on Project (5.4.4.2.A)

Project Summary	Continuation of the capital program started in 2018 to provide a solution, to a problem identified during the last Asset Condition Assessment, for replacement of directly buried primary & secondary conductors supplying residential services within the oldest Underground Distribution Residential Subdivisions within the Niagara Falls Service Territory. This program facilitates future rebuild by the installation of directional bored 4" & 3" HDPE conduit on the side of the road where primary and secondary co-exist, and a 4" HDPE conduit where only secondary is installed between all pad-mount foundations. Existing Cable would be "run to failure", at which time new cable would be installed utilizing these new ducts.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:** $603,505.05			
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** $0.00 **NPEI Estimated Cost:** $603,505.05			
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)				
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 1 2021 **In Service Date:** December 31 2021			
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$200,000	$200,000	$103,505.05	$100,000

Project Name: Subdivision Rehab Phase 3
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

As this project is low priority, it is scheduled around higher priority projects. The risks to schedule are obtaining locates for underground infrastructure and availability of contractors for directional boring and duct installation. The schedule for this program is very flexible, so accommodation of unforeseen delays is not an issue.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

This program began in 2017. Ducts have been installed at an average cost of $43.06 per meter.

- 2017, Total Cost $300,712.05, Total length of duct installed - 10.7km
- 2018/19, Total Cost $521,683.83, Total length of duct installed - 8.4km

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not applicable.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Project Name: Subdivision Rehab Phase 3
Category: System Renewal

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary investment driver is failure risk. NPEI's 2018 Asset Condition Assessment indentifies approximately 100 km of underground cable as flagged for action over the next 10 years. Evenly distributed, this represents approximately 10 km of cable per year. The focus of this program is direct buried cable. Proactively installing duct for replacement of direct buried cables that are run to failure is a logical and cost effective solution.

Good Utility Practice (5.4.3.2.B.1.b)

The objective of the program is develop a more resilient distribution system (cables in duct as opposed to direct buried) while addressing existing reliability and performance concerns (direct buried end of life cable).

Investment Priority (5.4.3.2.B.1.c)

NPEI's Project Priority Matrix ranks this investment as Low priority. It is ranked 22 out of 24 projects. System Renewal projects rank lower than System Access projects.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The effect on efficiency and cost-effectiveness are not immediately realized with this program. The work done is proactive and the benefits are realized once cable failure occurs. At that point, the replacement of faulted cable is quick and easy, resulting in very little outage time for customers.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

The net benefit to customers is a more reliable supply of electricity. The services supplying these customers will be run until failure at which point they will be replaced. By having the infrastructure in place now, the resulting outage will be significantly decreased.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

The impacts on outages is not immediately realized. However, when the underground cable inevitably failures, the amount and durations of outages required to remedy the solution will be reduced, due to having infrastructure in place. When the ducts are used, frequency and duration of outages will be reduced as cables within ducts operate more reliably than direct buried cable.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

One alternative would be repairing cables as they fail. This typically involves lengthy outages and several man hours to locate the fault. At this point that section requiring attention would be repaired. This option does not address the problem of the aged cables.

Scheduling Alternatives:

Scheduling is flexible and work is performed around other higher priority projects.

Project Name: Subdivision Rehab Phase 3
Category: System Renewal

Ownership Alternatives:

All assets are owned by NPEI.

Safety (5.4.3.2.B.2)

All work is performed by licensed contractors in accordance with NPEIs standards and Ontario Regulation 22/04 to ensure no undue safety hazards.

Cyber-Security and Privacy (5.4.3.2.B.3)

Not applicable.

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This program will be coordinated with the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln, the Town of Pelham, the Niagara Region, Bell Canada, Rogers, Cogeco and NRBN. Customers in the affected area will also be notified.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

Not applicable.

Environmental Benefits (5.4.3.2.B.2.B.5)

Not applicable.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable.

Category – Specific Requirements – System Renewal (5.4.4.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.4.2.C – SR.i.a)

This program doesn't actually replace direct buried cables, but provides the infrastructure necessary to do so in the future. NPEI's 2018 Asset Condition Assessment indentifies approximately 100 km of underground cable as flagged for action over the next 10 years. Evenly distributed, this represents approximately 10 km of cable per year

Asset Condition Relative to Typical Life Cycle (5.4.4.2.C – SR.i.b)

The typical life cycle of direct buried cable is 35. NPEI's asset condition assessment for underground cables was strictly based on age. As shown in the ACA, approximately 100 km of cable is ranked as "poor" or "very poor" condition. This is only considering primary cable, not secondary. Although the cable has performed well, and still is, it is necessary to prepare for replacement.

Number of Impacted Customers (5.4.4.2.C – SR.i.c)

The number of customers impacted will vary from project to project, the impact will be minimal as the program only addresses the installation of duct for future cable installation.

Quantitative Customer Impact and Risk (5.4.4.2.C – SR.i.d)

Although the impact won't be immediately realized, the effect of replacing direct buried cable with cable in duct is less frequent utages of shorter duration.

Project Name: Subdivision Rehab Phase 3
Category: System Renewal

Qualitative Customer Impact and Risk (5.4.4.2.C – SR.i.e)

Customer satisfaction will increase as customers are serviced with upgraded infrastructure, resulting in a more resilient distribution system.

Value of Customer Impact (5.4.4.2.C – SR.i.f)

The value of the customer impact is medium. Although the existing plant is still functioning, waiting until failure to begin work will result in a more costly and longer job. The customer will be forced to deal with longer outages to resolve the issue.

Factors Affecting Project Timing (5.4.4.2.C – SR.ii)

Higher priority projects may affect the timing. Adverse weather, availability of contractors, other work being done in the area.

Effect on System O&M Costs (5.4.4.2.C – SR.iii)

Direct buried cable is very challenging to work on. Isolating and fixing faults is a time consuming process involving a lot of man hours. Preparing for the replacement of end of life direct buried cable by installing duct work will lead to decreased O&M costs.

Impact on Reliability and Safety (5.4.4.2.C – SR.iv)

Cable installed in conduit is more reliable than direct buried cable. The impact will be increased reliability and safety. When digging, the duct work provides minor protection vs direct buried cable.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.4.2.C – SR.v)

Proactively installing conduit for future cable replacement is a excellent way to spread the cost of the upgrade while minimizing downtime for NPEI's customers. The benefits of cable installed in duct vs direct buried are clear.

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.4.2.C – SR.vi)

Like for like renewal would be installing more direct buried cable. Direct buried does not meet our current standards and is an antiquated way of serving subdivisions. The initial cost may be lower, but over time O&M costs would be driven up.

Project Sign-Off

Prepared By:	Weston Sagle	Authorized By:	
Date:	January 29, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	Switchgear	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	Niagara Falls

General Information on Project (5.4.4.2.A)

Project Summary	The Underground Equipment Inspection Program has identified a requirement for replacement of air insulated pad-mounted switchgear units, with dead-front stainless steel enclosure SF-6 Gas Insulated Equipment, due to corrosion and contamination issues, which will continue at a rate of 1 to 3 Units per year. Project scope involves the installation of applicable civil works such as manholes and duct-banks associated with the equipment replacement to current standards, using equipment constructed of Stainless Steel to avoid corrosion issues. Increased system reliability, Public & Personnel safety, and functionality are benefits of the program.
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:** $380,960.00
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** $0.00 **NPEI Estimated Cost:** $380,960.00
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	Pad-mounted switchgear units are typically placed in high density urban areas or near large commercial customers. They are used to provide flexibility for contingency scenarios, provide means of isolation/sectionalizing, and provide downstream line protection from the feeder breaker. The total number of customers impacted, and the connected load will be determined when the specific project scope is determined.
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 1, 2021 **In Service Date:** June 30, 2021

Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$200,000	$180,960	$0	$0

Project Name: Switchgear
Category: System Renewal

Images, Drawings, Maps, & Other Reference Material

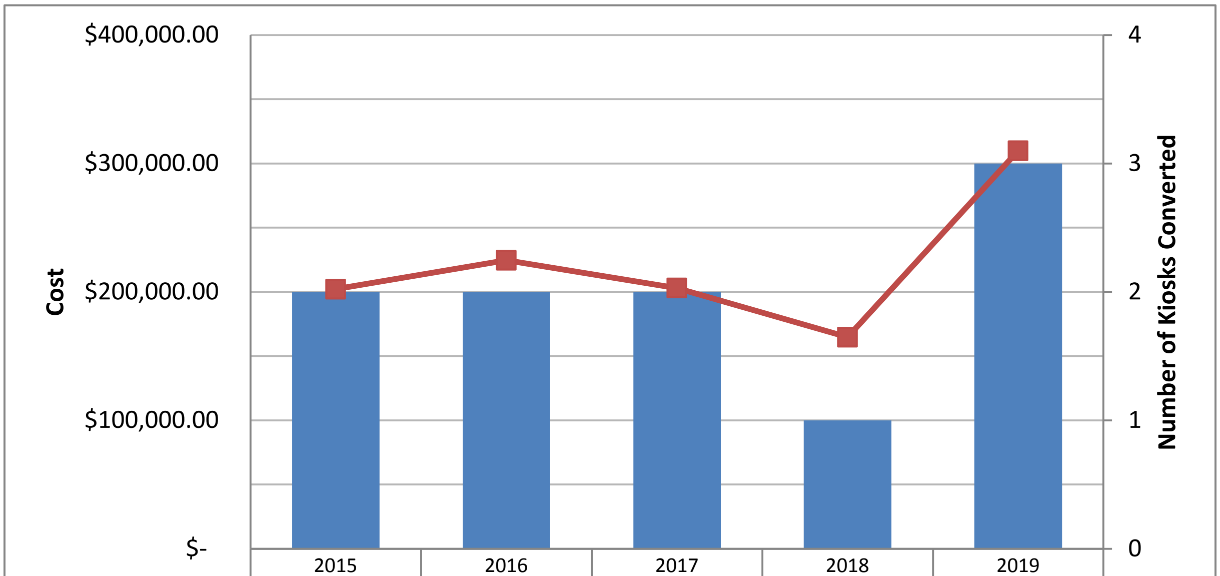
Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints. Manufacturers require 16-20 weeks for delivery for each unit pad-mount transformer. Material risk is mitigated by following NPEI's standard practice of ordering transformers on a regular basis and having spares on hand. By having a list of tagged transformers for replacement, labour resources can be planned accordingly to tackle transformers in a logical and cost effective manner.

Project Name: Switchgear
Category: System Renewal

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

This program has been in place for 5 years. Every year 2 to 3 locations are targeted for replacement. With the average cost per unit being $110,406.66 per unit. The historical cost breakdown is shown below:



	2015	2016	2017	2018	2019
Units Changed	2	2	2	1	3
Cost	$202,044.82	$224,569.53	$202,969.03	$164,654.78	$309,828.47

In 2021 we are budgeting to install 3 units at $380,960.00 or $126,986.67 per unit. These costs incorporate all installation and material costs associated with the replacement.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not Applicable

Leave to Construct Approval (5.4.3.2.A.viii)

Not Applicable

Project Name: Switchgear
Category: System Renewal

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary driver for this investment are the age and condition of the pad mounted switchgear. NPEI plans to address approximately 3 switchgear in 2021. The switchgear selected under this program will are typically chosen based on customer demand. Many times, when a new customer requests a service, nearby switchgear needs to be replaced/upgraded to in order to accommodate. Other replacements are chosen based on their age and condition. Worst case scenario is replacing switchgear upon failure.

Good Utility Practice (5.4.3.2.B.1.b)

NPEI has an ongoing yearly program to both inspect all underground equipment, which includes pad mounted switchgear. As well, items identified as requiring immediate replacement are addresses as soon as possible. The cycle for underground equipment inspection is as follows:

All underground equipment is inspected once every 3 Years for Urban Areas
All underground equipment is inspected once every 6 Years for Rural Areas

The source of information for the switchgear cost is based on historical costs for pad-mount transformers. Proactively replacing these transformers prior to failure will reduce the cost per transformer as the work can be performed during regular business hours avoiding overtime premiums.

Replacement of Pad-mount transformers will be completed in accordance with NPEI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. The transformer will be replaced with NPEI's current standard for Pad-mount transformers used throughout the NPEI system.

Investment Priority (5.4.3.2.B.1.c)

The overall investment priority of this project is medium, this program ranked 20 out of 24 projects in our Project Priority Matrix for 2021. NPEI views System Renewal projects as a lower priority than System Access projects, unless the condition of the assets poses an immediately risk to system stability and/or public safety. Within System Renewal projects this projects ranks as low priority as these assets tend to not pose an immediate risk to public safety.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Planned replacement of assets compared to replacement at failure offers several advantages. The cost per transformer is decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

By replacing aging pad mounted switchgear prior to failure, the costs associated with the replacement are drastically reduced. Further, the risk of an outage caused by failed equipment is greatly reduced and the duration of the outage to make the change is controllable and small.

Project Name: Switchgear
Category: System Renewal

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)
A Pad-mount switchgear failure can cause prolonged outages and cause damage to surrounding equipment. By replacing the switch gear prior to failure, the reliability for the customers serviced by these transformers is improved as it reduces the risk of an equipment failure. If required, having a scheduled outage to replace the switchgear will take far less time than changing a pad mounted switchgear unit that has failed at end of life.
Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)
Project Design Alternatives: Replace Pad Mount switchgear upon failure The only advantage to this option is up front cost savings which pales in comparison to the disadvantages. Overall total costs would be significantly higher as assets would be replaced on an emergency basis. Total quantity of outages would increase due to equipment failures and public safety would be put at risk. Scheduling Alternatives: As this program is a lower priority compared to other projects, the schedule as to when these jobs are complete can be flexible. However, as end of life asset replacement is deferred, there is an increased risk to public safety and system reliability decreases. Ownership Alternatives: This program consists solely of NPEI assets.
Safety (5.4.3.2.B.2)
Replacement of Pad-mount switchgear will be completed in accordance with NPEI's standards and Ontario Regulation 22/04 to ensure no undue safety hazards. The switch gear will be replaced with NPEI's current standard for pad mounted switchgear used throughout the NPEI system.
Cyber-Security and Privacy (5.4.3.2.B.3)
Not applicable
Co-ordination and Interoperability - **Co-ordination with utilities, regional planning and/or links with 3rd parties** (5.4.3.2.B.4.a)
This program will be coordinated with the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln, the Town of Pelham, the Niagara Region, Bell Canada, Rogers, Cogeco and NRBN. As well there will be coordination with the customer(s) affected by the switchgear replacement.
Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)
New switch gear ordered under this program will come equipped with programmable digital protection elements. The units deployed replace older versions of switchgear which used fuses for protection. The new switchgear are easier to reset under fault conditions and improve restoration times during outages.

Project Name: Switchgear
Category: System Renewal

Environmental Benefits (5.4.3.2.B.2.B.5)

Not applicable

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable

Category – Specific Requirements – System Renewal (5.4.4.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.4.2.C – SR.i.a)

The proposed program aims to target assets proactively whose condition has deteriorated to the extent that prudent measures must be taken to safeguard the performance of the system and public welfare

Operational Effectiveness - SAIDI and SAIFI will be improved by proactively replacing transformers before failure occurs
Safety - Replacing end of life pad mount switchgear avoids safety issues such as rusted equipment.
Customer Focus – Replacing switchgear, reduces the likelihood of long duration unplanned outages due to equipment failure.

Asset Condition Relative to Typical Life Cycle (5.4.4.2.C – SR.i.b)

NPEI has the typical life cycle of these assets as 30 years.

From the ACA report and data shown in section 5.4.3.2.B.1.a, 292 pad mount transformers have surpassed their useful life.

Number of Impacted Customers (5.4.4.2.C – SR.i.c)

The total number of customers impacted, and the connected load will be determined when the specific project scope is determined.

Quantitative Customer Impact and Risk (5.4.4.2.C – SR.i.d)

The average outage duration to change failed pad mount switchgear is approximately 4-6 hours. Therefore, if 60 customers are affected by this type of outage, it would equate to 360 customer hours.

Qualitative Customer Impact and Risk (5.4.4.2.C – SR.i.e)

If these transformers are not replaced, the risk of unplanned outages and outage duration will increase resulting in lower customer satisfaction. As pad mount switchgear is designed and configured for the location they are installed. If a compatible spare piece of equipment is not available, the switchgear may be isolated for an extended amount of time, which would reduce our system redundancy.

Value of Customer Impact (5.4.4.2.C – SR.i.f)

Value of customer impact is medium. A failure could result in an outage of several commercial customers for the duration of the outage. However, if the failure caused the feeder breaker to open, it could affect 1000’s of customers.

If pad-mount switchgear units are run until failure, there is a strong likelihood that forced outages will occur resulting in overtime required for response.

Project Name: Switchgear
Category: System Renewal

Factors Affecting Project Timing (5.4.4.2.C – SR.ii)

As this program focuses on planned replacement of assets still in operation, there is flexibility in scheduling. Coordination may be required to replace commercial customers to minimize outage durations and have minimal impact on their business.

Effect on System O&M Costs (5.4.4.2.C – SR.iii)

If pad mount transformers are run until failure, there is a strong likelihood that forced outages will occur resulting in overtime required for response.

By installing new pad mounted switchgear to current NPEI standards, there will be cost savings realized in inventory management as equipment is standardized.

New switch gear ordered under this program will come equipped with programmable digital protection elements. The units deployed replace older versions of switchgear which used fuses for protection. The new switchgear units are easier to reset under fault conditions and improve restoration times during outages. This ability to restore customers faster, will result in reduced O&M costs.

Impact on Reliability and Safety (5.4.4.2.C – SR.iv)

By proactively replacing the end of life switchgear, safety issues associated with equipment failures are avoided.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.4.2.C – SR.v)

Alternatives have been discussed in section (5.4.3.2.B.1.d.iii). The benefits to proactively replacing end of life pad-mount transformers are clear – new pad-mount switchgear increase safety and system reliability.

Replacing end of life pad-mount switchgear will avoid and/or reduce the frequency and duration of power outages. Maintaining the status quo will result in future outages which will lead to lengthy unplanned work and customer dissatisfaction.

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.4.2.C – SR.vi)

Replacement of switchgear is a like for like replacement.

Project Sign-Off

Prepared By:	Paul Uguccioni	Authorized By:	
Date:	February 3, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	System Sustainment	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Service	**Service Area:**	All

General Information on Project (5.4.4.2.A)

Project Summary	This capital program manages an allowance for minor projects initiated by unexpected failures/deficiencies of overhead and underground distribution facilities. Replacement of underground cable experiencing repeated failures is a major contributor covered by this allowance. Minor overhead system modifications and component replacements are also accounted for.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:** $888,460.00			
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:** $0.00 **NPEI Estimated Cost:** $888,460.00			
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	N/A			
Project Dates (5.4.3.2.A.iv)	**Start Date:** January 1, 2021 **In Service Date:** December 31, 2021			
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$222,115	$222,115	$222,115	$222,115

Project Name: System Sustainment
Category: System Renewal

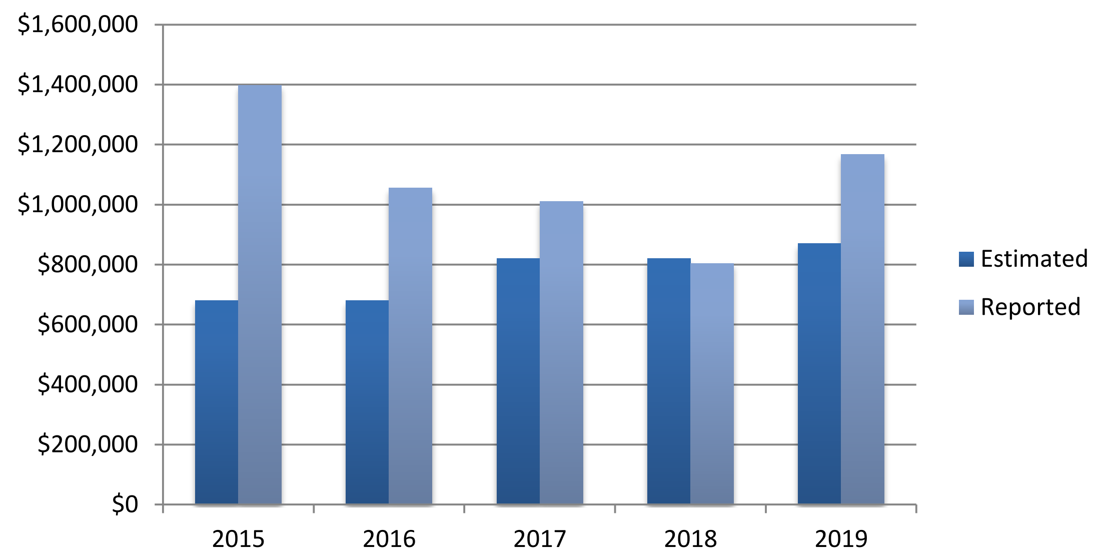
Images, Drawings, Maps, & Other Reference Material

Project Name: System Sustainment
Category: System Renewal

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints, approvals from applicable authorities and coordination with third parties. Risk mitigation is accomplished by completing the design and project scheduling in conjunction with Operations and Stores, coordinating with the road authority and third parties through the Public Utilities Coordinating Committee (PUCC).

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)



The chart above demonstrates Estimated vs Reported budgets from 2015 - 2019. It is apparent that over time, estimated and reported budgets have been converging. This is due to reducing System Service Spending while increasing the budget to better align with historical spending.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not applicable.

Leave to Construct Approval (5.4.3.2.A.viii)

Not applicable.

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The main drivers are safety and reliability. The investment is intended to capture the costs associated with the unexpected improvements of system assets that were not planned for the calendar year, but need to be replaced regardless. A major contributor to this budget is the replacement of underground cables experiencing repeated failures.

Project Name: System Sustainment
Category: System Renewal

Good Utility Practice (5.4.3.2.B.1.b)

This is an annual project put in place to address unexpected deficiencies of NPEI's overhead and underground distribution systems.

As part of NPEI's standard engineering practices, pole lines are designed and built to meet or exceed the latest revision of CSA C22.3 No.1. Overhead Systems, which ensures that new distribution system expansions, extensions and replacement are constructed to a level appropriate with the regional climate.

Investment Priority (5.4.3.2.B.1.c)

The investment priority is low, as demonstrated on the 2021 Project Priority Matrix. Although improvement of underperforming assets is important, when comparing to other System Access and System Renewal projects, System Service ranks lower.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The investment does not have a great effect on system operation efficiency and cost-effectiveness. The program allows NPEI to address issues as they arise. The program is important to service the system, and sometimes by doing this there are opportunities to increase efficiencies. Work is always scheduled in a cost-effective manner, although replacement upon failure/defect does sometimes involve after hours work.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Many of these projects are initiated due to customer demand. For example the city is rebuilding a road and has open trench, NPEI takes this opportunity to add ducts for future use. Ultimately all the work completed under this program is to ensure that the system remains operating, reliable and accessible, which is always a benefit to the customer.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Work performed under this program often arises from a failure or outage. In the case of direct buried cable, instead of replacing with more direct buried cable, installing a new duct structure increases reliability and—as a result—decreases the frequency and duration of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

As these projects aren't typically designed in far advance, alternatives are limited. When the need to replace or upgrade an asset arises, alternatives such as upgrades for future planning, relocating difficult to access poles, or using newer equipment and installation techniques are explored.

Scheduling Alternatives:

These projects are typically arise in response to an issue. In that sense, scheduling alternatives are limited, however, depending on the severity of the issue - projects are scheduled as appropriate.

Ownership Alternatives:

All assets are owned by NPEI.

Project Name: System Sustainment
Category: System Renewal

Safety (5.4.3.2.B.2)
All work is designed and constructed in accordance with NPEIs standards and Ontario Regulation 22/04 to ensure no undue safety hazards. Prior to energization, all worked is inspected and signed off by NPEI. Replacements of deteriorated poles, wires and vintage transformers drastically reduces the likelihood of catastrophic failure, resulting in possible downed wires. Downed wires poses the greatest risk to public and workers.
Cyber-Security and Privacy (5.4.3.2.B.3)
Not applicable.
Co-ordination and Interoperability - **Co-ordination with utilities, regional planning and/or links with 3rd parties** (5.4.3.2.B.4.a)
Work involved in this project is coordinated with the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln, the Town of Pelham, the Niagara Region, Bell Canada, Rogers, Cogeco and NRBN.
Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)
Future operational requirements may be improved under this program. If a section of line in experiences repeated issues, it may be beneficial to install a new set of switches for easier isolation of the section.
Environmental Benefits (5.4.3.2.B.2.B.5)
Not applicable.
Conservation and Demand Management (5.4.3.2.B.2.B.6)
Not applicable.
Category – Specific Requirements – System Service (5.4.3.2.C - SS)
Benefits to Customers vs. Cost Impact (5.4.3.2.C – SS.i)
According to NPEI's Customer Engagement report, the majority of customers feel that investing in the grid to maintain reliability is preferable to deferring investment to keep bills low. All projects are evaluated based on benefits to system reliability and operation, and impact on customers.
Regional Electricity Infrastructure Requirements (5.4.3.2.C – SS.i)
NPEI's service territory is undergoing significant growth, both residential and commercial. Although most of this work is captured under System Access, many smaller projects planning for future growth which may not be known at this point are captured in this program.
Advanced Technology (5.4.3.2.C – SS.iii)
Not applicable.
Reliability, Efficiency, Safety and Coordination Benefits (5.4.3.2.C – SS.iv)
If assets are left to operate until failure the customer impact is typically an outage. The length of the outage is a function of the asset, for example an underground cable failure may result in a longer outage that a pole mount transformer. The risk is a function of time, where as more time elapses, the risk increases. All projects selected are evaluated based on their impact to system reliability, efficiency and customer benefit.

Project Name: System Sustainment
Category: System Renewal

Factors Affecting Timing & Priority of Project (5.4.3.2.C – SS.v)

Many of the projects would be performed upon unexpected failure of an asset or by customer demand. Other project's timing would be affected by the asset location, health index of asset, results of pole loading calculations and historical system outage data. Priority is based on level of risk and impact on customers.

Analysis of Project Benefits and Costs ie. "Do Nothing" & "Technically Feasible Alternatives" (5.4.3.2.C – SS.vi)

Do nothing approach is always analyzed. In one case the city is rebuilding a road in the tourist district. There are open trenches and NPEI decides to add empty duct for future expansion. The cost of installing the duct now in substantially less than digging a trench and adding duct at a later date. Since it is near the tourist district, growth is inevitable.

Project Sign-Off

Prepared By:	Weston Sagle	Authorized By:	
Date:	January 27, 2020	Date:	
		Completion Date:	

Capital Project Summary

Project Name:	RBD Truck (TR#9) Replacement	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	General Plant	**Service Area:**	Smithville Service Centre

General Information on Project (5.4.4.2.A)

Project Summary	The vehicle replacement program includes the final payment for the body completion of the replacement RBD (TR#9) for the Smithville Service Centre.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$270,000.00		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	$0.00		
	NPEI Estimated Cost:	$270,000.00		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	N/A			
Project Dates (5.4.3.2.A.iv)	**Start Date:**	September 2021		
	In Service Date:	September 2021		
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	$0	$270,000	$0

Images, Drawings, Maps, & Other Reference Material

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The process involved in tendering, ordering and receiving a new large vehicle can take up to 18 months. Planning well ahead, preparing detailed specifications for each vehicle to be included with the tendering process, having a pre-construction meeting with the manufacturer and frequent correspondence during construction helps to minimize last minute changes before final inspection and ultimate scheduled delivery.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

In 2019, delivery of a similar RBD Truck (TR#59) was taken for the Niagara Falls service area. Body completion cost for this truck was $262K with an order placement in 2018. Pricing for the new TR#9 RBD received in 2020 for a 2021 final delivery is within 2% inflation.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

N/A

Leave to Construct Approval (5.4.3.2.A.viii)

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

Investment Driver (5.4.3.2.B.1.a)

Age and Condition – NPEI's policy is to replace large and small vehicles and equipment on a 10-12 year schedule. When finalizing replacements for a particular year, an overall assessment of the vehicle's mileage, engine hours, age, repair history, vehicle condition and future intended use is considered. The replacement of several small vehicles, trailers and equipment will be determined based on need.

Secondary Driver (5.4.3.2.B.1.a)

Reliability – The reliability of large vehicles in the fleet impact several areas including construction projects and response time to trouble calls. Equipment availability directly impacts crew productivity and scheduled replacements reduces the risk of unplanned vehicle and equipment failures.

Good Utility Practice (5.4.3.2.B.1.b)

N/A

Investment Priority (5.4.3.2.B.1.c)

It is important that all fleet vehicles are maintained properly and replaced in a timely manner, keeping overall costs in mind. This requires balancing new vehicle costs against excessive repair bills and operational downtimes that occurs when vehicles are kept for too long.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The reliability of large vehicles in the fleet impact several areas including construction projects and response time to trouble calls. Equipment availability directly impacts crew productivity and scheduled replacements reduces the risk of unplanned vehicle and equipment failures.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Net benefits to customers include maintaining and improving response times to outages, system reliability and crew effectiveness.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Net benefits to customers include maintaining and improving response times to outages, system reliability and crew effectiveness.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

When the age of a vehicle approaches its end of life, a case by case evaluation is done to determine whether or not replacement is an option ahead of or later than the vehicles normal life expectancy. The life expectancy for vehicles is based on long-term experience with residual values at times of sale and are driven by odometer readings, engine hours, maintenance records and depreciation policy.

Scheduling Alternatives:

It is important that all fleet vehicles are maintained properly and replaced in a timely manner, keeping overall costs in mind. This requires balancing new vehicle costs against excessive repair bills and operational downtimes that occurs when vehicles are kept for too long.

Ownership Alternatives:

N/A

Safety (5.4.3.2.B.2)

Risks increase when associated with aging vehicles and equipment, including ergonomic impacts, employee safety and efficiency.

Cyber-Security and Privacy (5.4.3.2.B.3)

N/A

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

N/A

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This investment does not directly enable future technological functionality or operational requirements.

Environmental Benefits (5.4.3.2.B.2.B.5)

Newer vehicles are generally more fuel efficient and have less emissions which are both environmental benefits.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

N/A

Category – Specific Requirements – General Plant (5.4.4.2.C - GP)

Quantitative and Qualitative Analyses, Business Case documenting the justifications for the expenditure (5.4.4.2.C – GP.i)

Tendering for larger expenses through the normal purchasing policy enables quantitative and qualitative analysis for truck replacements.

Business Case Documenting the Justifications for the Expenditure, Alternatives Considered, Benefits for Customers (short/long term), and Impact on Distributor Costs (short/long term) (5.4.4.2.C – GP.ii)

Replacement of end of life vehicles is a routine activity.

Project Sign-Off

Prepared By:	Shanon Wilson	Authorized By:	
Date:	January 23, 2020	Date:	
		Completion Date:	

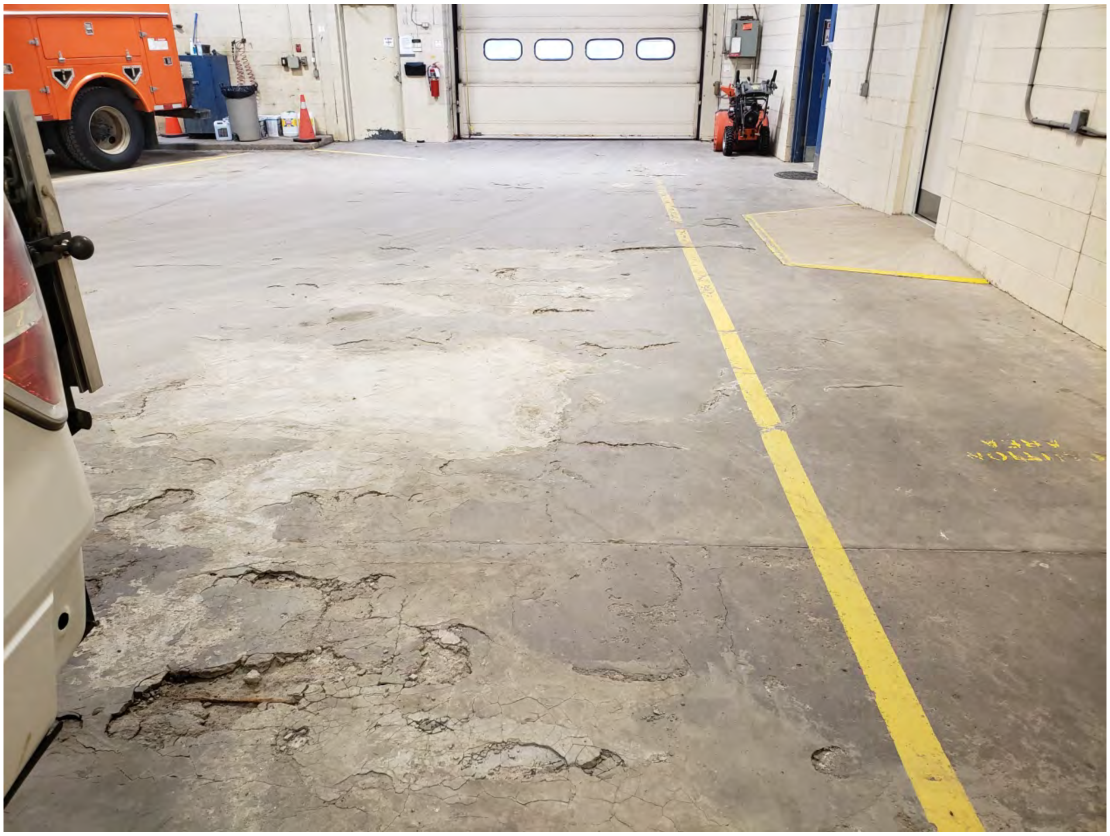
Capital Project Summary

Project Name:	7447 Pin Oak Dr. Service Centre Concrete Floor Repair	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	General Plant	**Service Area:**	Niagara Falls

General Information on Project (5.4.4.2.A)

Project Summary	The Niagara Falls garage was built in 1984. It has been housing NPEI's large vehicles since that time. Over time the floor of the garage has been degrading. Patch repairs have been completed in the past but repairs are reoccurring and becoming more frequent. This is causing greater safety risk of slips, trips and falls. A complete repair of the garage floor requires resurfacing of approximately 12,300 square feet of floor along with the replacement of trench drain system. An in-floor heating system would be installed to replace the less efficient radiant heating system.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$400,000.00		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	$0.00		
	NPEI Estimated Cost:	$400,000.00		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	N/A			
Project Dates (5.4.3.2.A.iv)	**Start Date:**	September 2021		
	In Service Date:	October 2021		
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$0	$0	$100,000	$300,000

Images, Drawings, Maps, & Other Reference Material



Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The process involved in tendering, ordering and receiving a new large vehicle can take up to 18 months. Planning well ahead, preparing detailed specifications for each vehicle to be included with the tendering process, having a pre-construction meeting with the manufacturer and frequent correspondence during construction helps to minimize last minute changes before final inspection and ultimate scheduled delivery.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

There are no comparable projects that are equivalent in nature. NPEI has one other vehicle garage but it has not required this type of project. NPEI's purchasing policy will be followed in the tendering process.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

N/A

Leave to Construct Approval (5.4.3.2.A.viii)

N/A

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

Investment Driver (5.4.3.2.B.1.a)

Age and Condition – Over time the floor of the garage has been degrading. Patch repairs have been completed in the past but repairs are reoccurring and becoming more frequent. This is causing greater safety risk of slips, trips and falls.

Secondary Driver (5.4.3.2.B.1.a)

Efficiency – An in-floor heating system would be installed to replace the less efficient radiant heating system.

Good Utility Practice (5.4.3.2.B.1.b)

N/A

Investment Priority (5.4.3.2.B.1.c)

It is important that all facilities are maintained properly and repaired in a timely manner, keeping overall costs in mind. This requires balancing replacement costs against excessive repair bills and potential health and safety risks, which may occur if the facility repairs fail to perform.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The patch repairs have been completed in the past but repairs are reoccurring and becoming more frequent and less cost effective. This is causing greater safety risk of slips, trips and falls. With the rebuild of the concrete floor, the opportunity to achieve energy efficiency via incorporation of in-floor radiant heat is possible.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Net benefits to customers include more efficient utilization of O&M funds.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

N/A – no impact on distribution system reliability.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

None. Replacement has been deferred for several years as various floor patching attempts have been made. Continued patching on an annual or more frequent basis is not feasible.

Scheduling Alternatives:

Work to be scheduled when weather permits parking of vehicles outside to accommodate the work.

Ownership Alternatives:

N/A

Safety (5.4.3.2.B.2)

Patch repairs have been completed in the past but repairs are reoccurring and becoming more frequent. This is causing greater safety risk of slips, trips and falls.

Cyber-Security and Privacy (5.4.3.2.B.3)

N/A

Co-ordination and Interoperability - **Co-ordination with utilities, regional planning and/or links with 3rd parties** (5.4.3.2.B.4.a)

N/A

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

This investment does not directly enable future technological functionality or operational requirements.

Environmental Benefits (5.4.3.2.B.2.B.5)

Incorporating in-floor radiant heating to replace the inefficient ceiling mount radiant heating will provide cost efficiency and environmental benefits.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

N/A

Category – Specific Requirements – General Plant (5.4.4.2.C - GP)

Quantitative and Qualitative Analyses, Business Case documenting the justifications for the expenditure (5.4.4.2.C – GP.i)

Tendering for larger expenses through the normal purchasing policy enables quantitative and qualitative analysis for facility rebuilds.

Business Case Documenting the Justifications for the Expenditure, Alternatives Considered, Benefits for Customers (short/long term), and Impact on Distributor Costs (short/long term) (5.4.4.2.C – GP.ii)			
Proper facilities lifecycle maintenance is a routine activity.			
Project Sign-Off			
Prepared By:	Shanon Wilson	Authorized By:	
Date:	January 23, 2020	Date:	
		Completion Date:	

Appendix B:
IRRP – Integrated Regional Resource Planning

Niagara

The regional planning process for this region is complete for this planning cycle. It will begin again within the five-year time frame unless there is sufficient load growth or a trigger event that requires it to begin earlier.

Area Overview

For regional planning purposes, the Niagara region includes the City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-on-the-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham. Haldimand County has also been included in the regional infrastructure planning needs assessment for Niagara region.

The local distribution companies providing service to customers in the Niagara region include:

Alectra Utilities

Canadian Niagara Power Inc.
(Port Colborne/Fort Erie/Niagara Falls)

Grimsby Power Inc.

Hydro One Networks Inc.

Niagara Peninsula Energy Inc.

Niagara-on-the-Lake Hydro Inc.

Welland Hydro-Electric System Corporation

Regional Planning Process Status

The local transmitter (Hydro One) has completed the Needs Assessment for this planning region and found that there were no needs that required regional coordination, completing the regional planning process for this planning cycle. The process will begin again within the five-year regional planning time frame, or earlier if there is sufficient load growth or a trigger event that requires initiating the process before that time.

A copy of the transmitter's Needs Assessment report can be viewed on Hydro One's website.

Niagara

Regional Infrastructure Plan ("RIP")

March 28th 2017

Canadian Niagara Power Inc.
Grimsby Power Inc.
Horizon Utilities Corporation Inc.
Hydro One Networks Inc. (Distribution)
Niagara Peninsula Energy Inc.
Niagara-On-the-Lake Hydro Inc.
Welland Hydro-Electric System Corporation

The Niagara Region includes the municipalities of City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-On-The-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham.

The Needs Assessment ("NA") report for the Niagara Region was completed on April 30th, 2016 (see attached). The report concluded that there were only two needs in the Region and that they should be addressed as follows:

- Thermal overloading of 115kV circuit Q4N: Addressed in a Local Plan ("LP") report.

The loading constraints on 115kV circuit Q4N was addressed in a LP report led by Hydro One Networks Inc. and published on November 11th, 2016. The report concluded that Hydro One already has plans to replace the existing section of conductor between Sir Adam Beck SS #1 and Portal JCT with a 910A continuous rating conductor at 93°C as part of their Beck #1 SS Refurbishment project. The expected in-service date for this conduction section upgrade is December 2019.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the RIP for the Niagara Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2021) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks Inc.

[1] Planning Process Working Group (PPWG) Report to the
Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

Appendix C:
RIP – Regional Infrastructure Planning

Niagara

Regional Infrastructure Plan ("RIP")

March 28th 2017

Canadian Niagara Power Inc.
Grimsby Power Inc.
Horizon Utilities Corporation Inc.
Hydro One Networks Inc. (Distribution)
Niagara Peninsula Energy Inc.
Niagara-On-the-Lake Hydro Inc.
Welland Hydro-Electric System Corporation

The Niagara Region includes the municipalities of City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-On-The-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham.

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Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks Inc.

[1] Planning Process Working Group (PPWG) Report to the
Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

Hydro One Networks Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
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Ajay.Garg@HydroOne.com

Niagara
Regional Infrastructure Plan ("RIP")

March 28th 2017

Canadian Niagara Power Inc.
Grimsby Power Inc.
Alectra Utilities
Hydro One Networks Inc. (Distribution)
Niagara Peninsula Energy Inc.
Niagara-On-the-Lake Hydro Inc.
Welland Hydro-Electric System Corporation

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The next planning cycle for the region will take place within five years of the start of this cycle (2021) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks Inc.

[1] Planning Process Working Group (PPWG) Report to the Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

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

NEEDS ASSESSMENT REPORT

Region: Niagara

Date: April 30th 2016

Prepared by: Niagara Region Study Team

Niagara Study Team
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)
Canadian Niagara Power Inc.
Grimsby Power Inc.
Haldimand County Hydro Inc.
Horizon Utilities Corp.
Niagara Peninsula Energy Inc.
Niagara on the Lake Hydro Inc.
Welland Hydro Electric System Corp.

DISCLAIMER

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Niagara region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or 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"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

Region	Niagara (the "Region")		
Lead	Hydro One Networks Inc. ("Hydro One")		
Start Date	October 15, 2015	End Date	April 30th 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Niagara Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the Niagara Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The Niagara Region belongs to Group 3. The NA for this Region was triggered on October 15, 2015 and was completed on April 30th 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2025. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One transmission provided information for the Niagara Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2015 to 2024). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Needs

A. Transmission Lines & Ratings

The 230kV and 115kV lines are adequate over the study period with a section of 115kV circuit Q4N being the exception.

B. 230 kV and 115 kV Connection Facilities

The 230kV and 115kV connection facilities in this region are adequate over the study period.

System Reliability, Operation and Restoration Review

There are no known issues with system reliability, operation and restoration in the Niagara region.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following sustainment work is currently planned by Hydro One in the region:

- DeCew Falls SS: Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1: 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS: Switchgear Replacement (2020)
- Sir Adam Beck SS #2: 230kV Circuit Breakers Replacement (2020)
- Glendale TS: Station Refurbishment and Reconfiguration (2021)
- Stanley TS: Station Refurbishment (2021)
- Thorold TS: Transformer Replacement (2021)
- Crowland TS: Transformer Replacement (2021)

Based on the findings of the Needs Assessment, the study team recommends that thethermal overloading of 115kV circuit Q4N shouldbe further assessed as part of a Local Plan. No further regional coordination or planning is required.

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1 Introduction

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Niagara Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the Niagara Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain local type of needs if straight forward wires solutions can address a need. Ultimately, assessment and findings of the local plans are incorporated in the RIP for the region.

This report was prepared by the Niagara Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for Niagara Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Canadian Niagara Power Inc.
4	Grimsby Power Inc.
5	Haldimand County Hydro Inc
6	Horizon Utilities Corp.
7	Hydro One Networks Inc. (Distribution)
8	Niagara Peninsula Energy Inc.
9	Niagara on the Lake Hydro Inc.
10	Welland Hydro Electric System Corp.

2 Regional Issue / Trigger

The NA for the Niagara Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Niagara Region belongs to Group 3.

3 Scope of Needs Assessment

This NA covers the Niagara Region over an assessment period of 2015 to 2024. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

3.1 Niagara Region Description and Connection Configuration

For regional planning purposes, the Niagara region includes the City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-on-the-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham. Haldimand County has also been included in the regional infrastructure planning needs assessment for Niagara region. A map of the region is shown below in Figure 1.

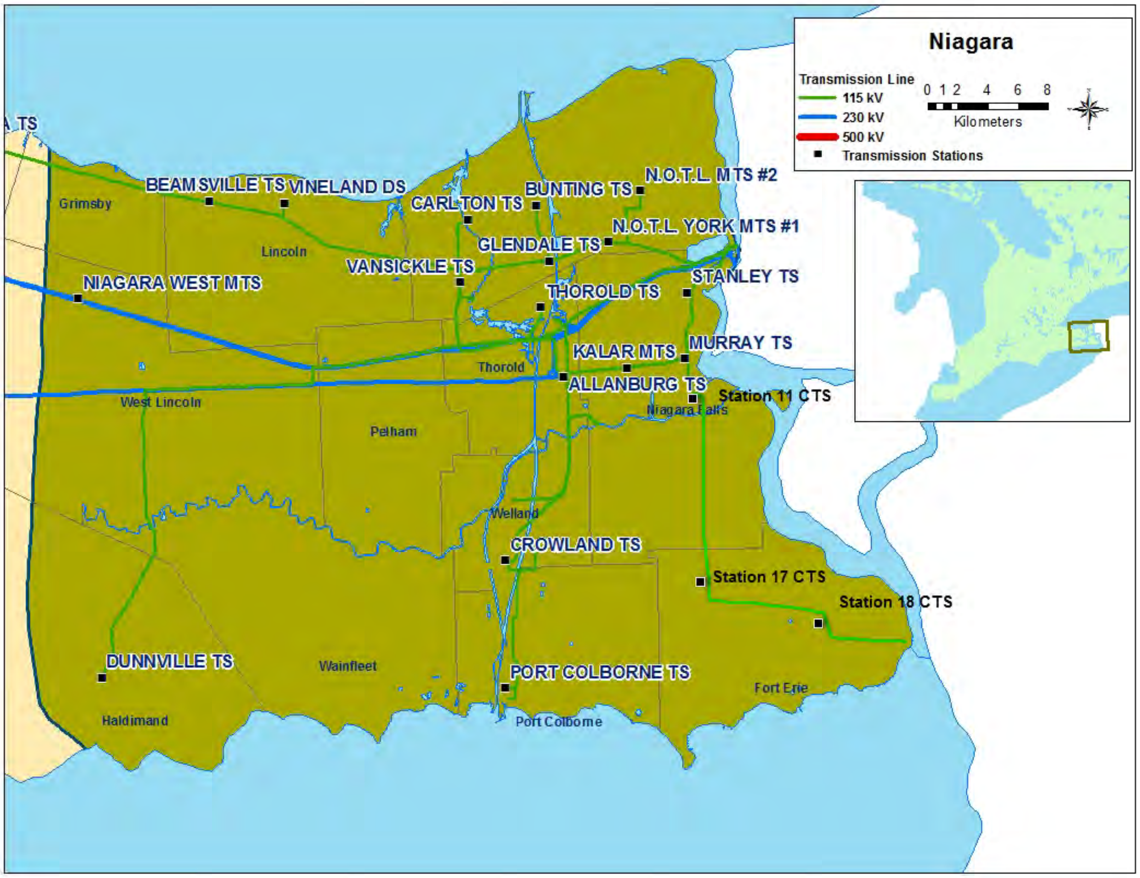

Figure 1: Niagara Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck #1, Sir Adam Beck #2, Decew Falls GS, Thorold GS and the autotransformers at Allanburg TS.

Bulk supply is provided through the 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) from Sir Adam Beck #2 SS. These circuits connect this region to Hamilton/Burlington.

The Niagara Region has the following local distribution companies (LDC):

- Canadian Niagara Power Inc.
- Grimsby Power Inc.
- Haldimand County Hydro Inc.
- Horizon Utilities
- Hydro One Distribution Inc.
- Niagara Peninsula Energy Inc.
- Niagara on the Lake Hydro Inc.
- Welland Hydro Electric System Corporation

Large transmission connected customers in the area will not actively participate in the regional planning process, however their load forecasts will used in determining regional supply needs.

Table 2: Transmission Lines and Stations in Niagara Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Customer Transformer Stations
Q3N, Q4N, Q11S, Q12S, Q2AH, A36N, A37N, D9HS, D10S, D1A, D3A, A6C, A7C,C1P, C2P	Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M, Q21P, Q22P	Allanburg TS*, Stanley TS, Niagara Murray TS, Thorold TS, Vansickle TS, Carlton TS, Glendale TS, Bunting TS, Dunville TS, Vineland TS, Beamsville TS, Sir Adam Beck SS #1, Sir Adam Beck SS #2, Crowland TS, Port Colborne TS	Niagara on the Lake #1 and #2 MTS, CNPI Station 11 , CNPI Station 17, CNPI Station 18, Kalar MTS, Niagara West MTS

Stations with Autotransformers installed

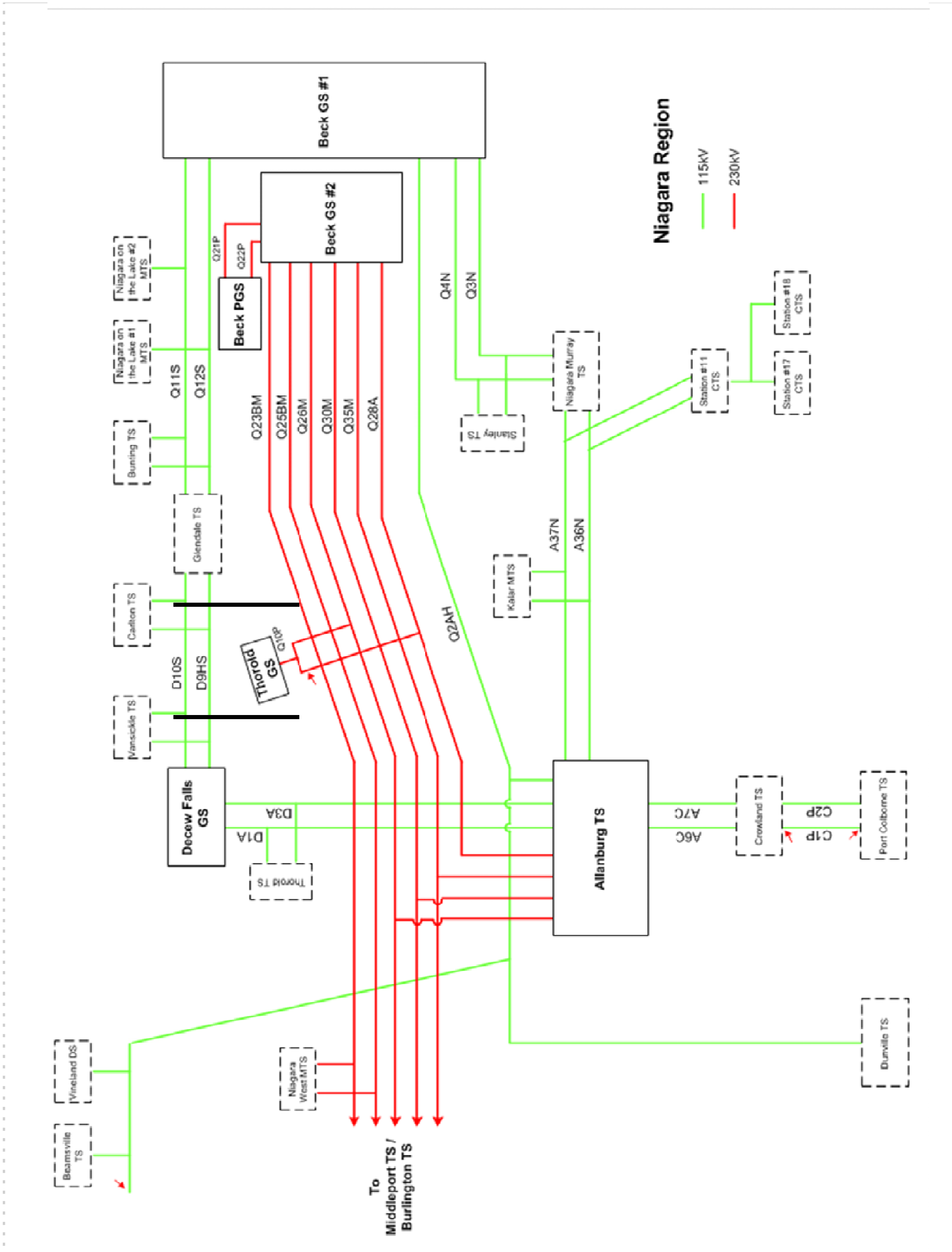

Figure 2: Simplified Niagara Regional Planning Electrical Diagram

4 Inputs and Data

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- Actual 2013 regional coincident peak load and station non-coincident peak load provided by IESO;
- Historical (2012-2014) net load and gross load forecast (2015-2024 provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by IESO;
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per the data provided by the study team, the gross load in region is expected to grow at an average rate of approximately 0.61% annually from 2015-2024.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to decrease at an average rate of approximately 0.26% annually from 2015-2024.

5 Needs Assessment Methodology

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

1. The Region is summer peaking so this assessment is based on summer peak loads.
2. Forecast loads are provided by the Region's LDCs.
3. Load data for the industrial customers in the region were assumed to be consistent with historical loads.
4. Accounting for (2), (3), above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG are analyzed to determine if the needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report.

5. Review impact of any on-going and/or planned development projects in the Region during the study period.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR). Summer LTR ratings were reviewed to assess the worst possible loading scenario from a ratings perspective.
8. Extreme weather scenario factor at 1.037 was also assessed for capacity planning over the study term.
9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their summer long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using summer loading with summer 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.

- With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 Results

6.1 Transmission Capacity Needs

230/115 kV Autotransformers

The 230/115kV transformers supplying the region are adequate for loss of single unit.

Transmission Lines & Ratings

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

The 115 kV circuits supplying the Region are adequate over the study period with Q4N as an exception between Sir Adam Beck SS #1 x Portal Junction.

230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station summer peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario.

6.2 System Reliability, Operation and Restoration

6.2.1 Load Restoration

Load restoration is adequate in the area and meet the ORTAC load restoration criteria.

The needs assessment did not identify any additional issues with meeting load restoration as per the ORTAC load restoration criteria.

6.2.2 Thermal Overloading on Q4N Section

Under high generation scenarios at Sir Adam Beck GS #1, the loading on the *Beck SS #1 x Portal Junction* section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings. Hydro One already has plans to address this issue as part of the Beck SS #1 Refurbishment Project.

6.2.3 Power Factor at Thorold TS

A few instances (<54 hours / year) of power factor below 0.9 (between 0.89 - 0.9) were observed at the HV side of Thorold TS. Hydro One Distribution will investigate these instances and work with Distribution customers to address.

7 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers and power transformers during the study period. At this time, the following sustainment work is planned at the following stations:

- DeCew Falls SS Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS; Switchgear Replacement (2020)
- Sir Adam Beck SS #2 230kV Circuit Breakers Replacement (2020)
- Glendale TS; Station Refurbishment and Reconfiguration (2021)
- Stanley TS; Station Refurbishment (2021)
- Thorold TS; Transformer Replacement (2021)
- Crowland TS; Transformer Replacement (2021)

8 Recommendations

Based on the findings and discussion in Section 6 and 7 of this report, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

9 Next Steps

No further Regional Planning is required at this time. The Niagara Region Regional Planning will be reassessed during the next planning cycle or at any time should unforeseen conditions or needs warrant to initiate the regional planning for the region.

10 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO 18-Month Outlook: March 2014 – August 2015

iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

Appendix A: Non-Coincident Winter Peak Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
NPEI - Embedded	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
Grimsby Power, NPEI - Embedded	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
Crowland TS	Net Load Forecast	89.1	93.6	74.6										
Welland Hydro	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
Hydro One, CNPI - Embedded	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Haldimand County Hydro	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
Hydro One - Embedded	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
NPEI - Embedded	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
NPEI Embedded	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
	Gross Peak Load - DG - CDM				52.1	51.7	51.5	51.1	50.8	50.5	50.4	50.3	50.3	50.2
Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland TS	Net Load Forecast	17.4	17.0	17.0										
Hydro One	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
NPEI - Embedded	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Networks Inc.
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LOCAL PLANNING REPORT

Q4N THERMAL OVERLOAD

Region: Niagara

Revision: Final
Date: November 11th 2016

Prepared by: Niagara Region Study Team

Niagara Region Local Planning Study Team
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Canadian Niagara Power Inc.
Grimsby Power Inc.
Haldimand County Hydro Inc.
Horizon Utilities Corp.
Niagara Peninsula Energy Inc.
Niagara on the Lake Hydro Inc.
Welland Hydro Electric System Corp.

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Niagara Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	Niagara Region ("Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	16 May 2016	**END DATE**	1 November 2016

1. INTRODUCTION

The purpose of this Local Planning ("LP") report is to develop and recommend a preferred wires solution that will address the local needs identified in the Needs Assessment (NA) report for the Niagara Region. The development of the LP report is in accordance with the regional planning process as set out in the Planning Process Working Group ("PPWG") Report to the Ontario Energy Board's ("OEB") and mandated by the Transmission System Code ("TSC") and Distribution System Code ("DSC").

2. LOCAL NEEDS REVIEWED IN THIS REPORT

This report reviewed the potential thermal rating violation for the Beck SS #1 x Portal Junction section of the 115kV Q4N circuit (egress out from Sir Adam Beck GS #1).

3. OPTIONS CONSIDERED

The following options were considered:

- Option 1: Status Quo
- Option 2: Uprate Circuit Section

4. PREFERRED SOLUTIONS

Option 2 is the preferred option. The uprating of limiting section of the circuit is included in Hydro One's Sustainment plan.

5. RECOMMENDATIONS

It is recommended that the circuit section upgrade proceed with current with an expected in-service date of December 2019.

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LIST OF FIGURES

1 Introduction

The Needs Assessment (NA) for the Niagara Region ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. The NA for the Niagara Region was prepared jointly by the study team, including LDCs, Independent Electric System Operator (IESO) and Hydro One. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the Region over the next ten years (2015 to 2024) and recommended that they should be further assessed through the transmitter-led Local Planning (LP) process.

As part of the NA report for the Niagara Region, it identified that under high generation scenarios at Sir Adam Beck GS #1, the loading on the Beck SS #1 x Portal Junction section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings in IESO's System Impact Assessment for the Sir Adam Beck-1 GS – Conversion of units G1 and G2 to 60 Hz

This Local Planning report was prepared by Hydro One Networks Inc. ("HONI"). This report captures the results of the assessment based on information provided by LDCs and HONI.

2 Regional Description and Circuit Q4N Description

Sir Adam Beck GS #1 is an 115kV hydroelectric generating station located on the Niagara Escarpment north of Niagara Falls in Queenston. Geographically, it roughly borders Highway 405 and the Canadian-American border via the Niagara River.

Electrical supply from Sir Adam Beck GS #1 is currently provided through eight (8) OPG generators connected to Hydro One's 115kV solid 'E' bus inside the station. Supply to the local 115kV area is delivered via five (5) Hydro One circuits (Q2AH, Q3N, Q4N, Q11S, Q12S) from 115kV 'E' bus within the power house. The 115 kV 'E' bus serves as a switching station for the Hydro One network as well as a connection facility for OPGI's generators. The generators, transformers and circuits on the 'E' bus are sectionalized via switches.

A single line diagram is shown of the 115 kV system originating from the 115kV Sir Adam Beck GS #1 in Figure 1.

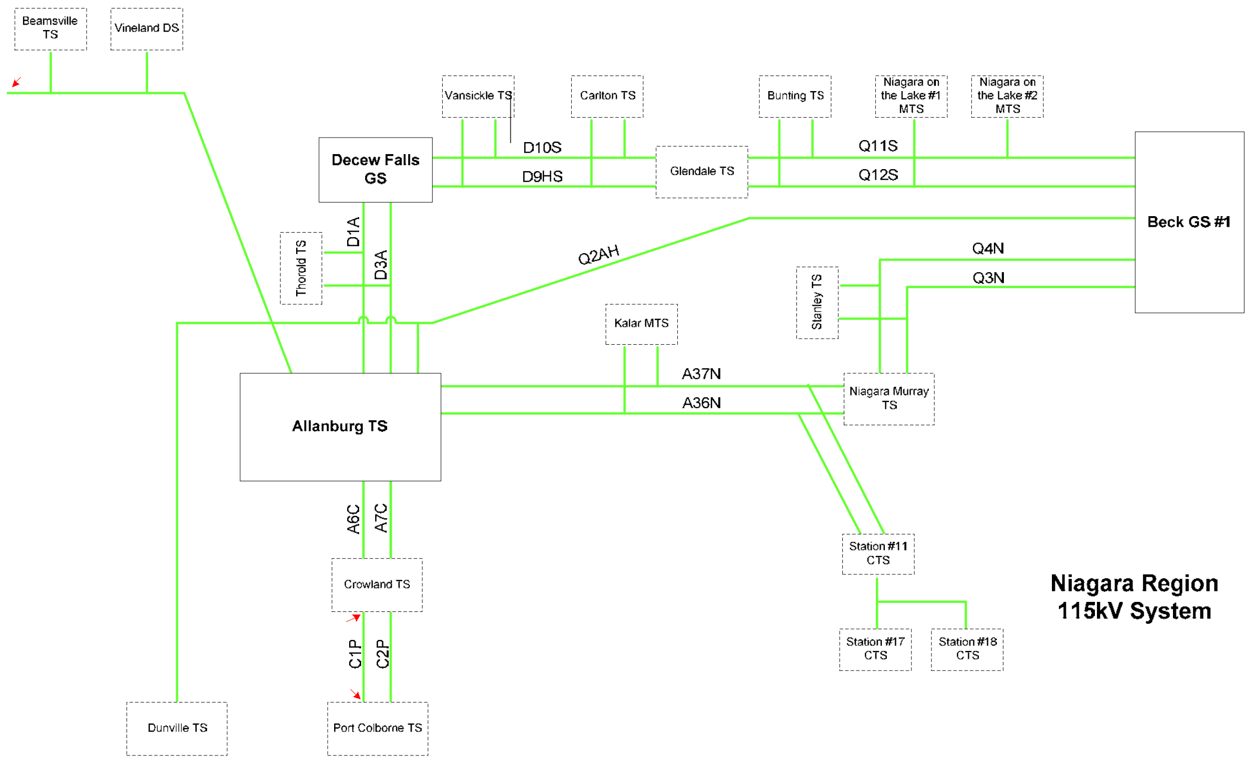

Figure 1: Single Line Diagram – Niagara Region 115kV System

From the NA report for the Niagara Region, a possible thermal limit issue on a section of the circuit Q4N was identified. Q4N is an approximately 9 km long, 115kV radial circuit from Sir Adam Beck GS #1, supplying Stanley TS and Niagara Murray TS.

The section of Q4N identified in the NA comprises of the section from Sir Adam Beck GS #1 to Portal Junction. This section of circuit is shown in Figure 2.

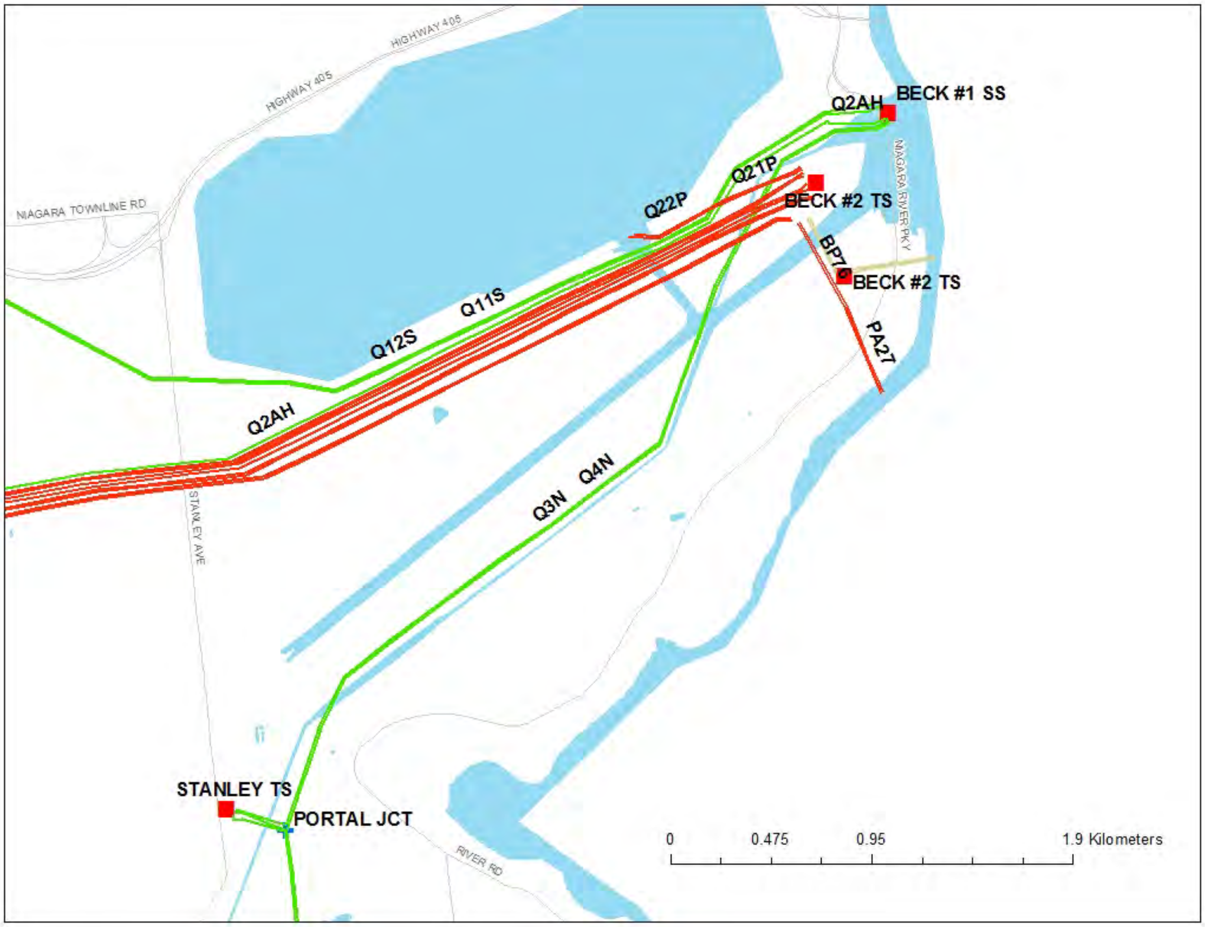

Figure 2: Single Line Diagram – Q4N from Beck #1 SS to Portal Junction

3 Local Niagara Need (Q4N)

In the past decade, OPG has been steadily increasing the power output of their generators with station upgrades.

In the IESO SIA for “Sir Adam Beck-1 GS – Conversion of units G1 and G2 to 60 Hz” it was identified that the thermal loading on circuit section Q4N from Beck #1 SS to Portal junction exceeds its continuous rating by 109.6% at total generation output of Sir Adam Beck #1 GS. This study was based on 2018 summer peak demand with high generation dispatch in the 115 kV transmission system in the vicinity with the existing 8 generators and 2 future generators (G1 and G2) at full output. This thermal loading is based on an ambient 35ºC temperature condition with 4 km/hr wind speed during daytime.

Reducing the generation output of Sir Adam Beck #1 GS from its maximum capacity of 556 MW to 509 MW reduces the loading on Q4N (Beck #1 SS by Portal Junction) to below its continuous rating.

4 Study Result / Options Considered

The conductor on a 64m section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal Jct. is comprised of 605.0 kcmil aluminum, 54/7 ACSR. The continuous rating for this type of conductor at 93^{o}C is 680A. The options considered are outlined below.

4.1 Option 1: Status Quo

Status Quo is not an option because there is a risk that for maximum generation dispatch in extreme weather conditions. Under these conditions generation would have to be curtailed to meet line thermal rating requirements and thus causing financial losses to customer.

4.2 Option 2: Uprate Conductor Section

Hydro One has plans already in place to replace the existing section of conductor with a 910A continuous rated conductor at 93^{o}C as part of their Beck #1 SS Refurbishment project. This will enable this section of circuit to meet all pre and post contingency thermal limits during max generation and under extreme weather conditions.

5 Recommendations

It is recommended that Hydro One continues with their sustainment plans (Option 2) on replacing the section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal Jct. with a larger ampacity conductor (increase of 680A to 910A).

The expected in-service date for this conduction section upgrade is December 2019.

6 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
iii) Needs Assessment Report Niagara Region

Appendix A: Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One, NPEI - Embedded	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One & NPEI, Grimsby Power, NPEI - Embedded	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
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Welland Hydro & Hydro One, CNPI - Embedded	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Hydro One	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One & NPEI	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power, NPEI Embedded	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
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Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland DS	Net Load Forecast	17.4	17.0	17.0										
Hydro One, NPEI - Embedded	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

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

NEEDS ASSESSMENT REPORT

Region: Niagara

Date: April 30th 2016

Prepared by: Niagara Region Study Team

Niagara Study Team
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)
Canadian Niagara Power Inc.
Grimsby Power Inc.
Haldimand County Hydro Inc.
Horizon Utilities Corp.
Niagara Peninsula Energy Inc.
Niagara on the Lake Hydro Inc.
Welland Hydro Electric System Corp.

DISCLAIMER

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Niagara region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or 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"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

Region	Niagara (the "Region")		
Lead	Hydro One Networks Inc. ("Hydro One")		
Start Date	October 15, 2015	End Date	April 30th 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Niagara Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the Niagara Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The Niagara Region belongs to Group 3. The NA for this Region was triggered on October 15, 2015 and was completed on April 30th 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2025. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One transmission provided information for the Niagara Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2015 to 2024). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Needs

A. Transmission Lines & Ratings

The 230kV and 115kV lines are adequate over the study period with a section of 115kV circuit Q4N being the exception.

B. 230 kV and 115 kV Connection Facilities

The 230kV and 115kV connection facilities in this region are adequate over the study period.

<u>System Reliability, Operation and Restoration Review</u>

There are no known issues with system reliability, operation and restoration in the Niagara region.

<u>Aging Infrastructure / Replacement Plan</u>

Within the regional planning time horizon, the following sustainment work is currently planned by Hydro One in the region:

- DeCew Falls SS: Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1: 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS: Switchgear Replacement (2020)
- Sir Adam Beck SS #2: 230kV Circuit Breakers Replacement (2020)
- Glendale TS: Station Refurbishment and Reconfiguration (2021)
- Stanley TS: Station Refurbishment (2021)
- Thorold TS: Transformer Replacement (2021)
- Crowland TS: Transformer Replacement (2021)

Based on the findings of the Needs Assessment, the study team recommends that thethermal overloading of 115kV circuit Q4N shouldbe further assessed as part of a Local Plan. No further regional coordination or planning is required.

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1 Introduction

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Niagara Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the Niagara Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain local type of needs if straight forward wires solutions can address a need. Ultimately, assessment and findings of the local plans are incorporated in the RIP for the region.

This report was prepared by the Niagara Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for Niagara Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Canadian Niagara Power Inc.
4	Grimsby Power Inc.
5	Haldimand County Hydro Inc
6	Horizon Utilities Corp.
7	Hydro One Networks Inc. (Distribution)
8	Niagara Peninsula Energy Inc.
9	Niagara on the Lake Hydro Inc.
10	Welland Hydro Electric System Corp.

2 Regional Issue / Trigger

The NA for the Niagara Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Niagara Region belongs to Group 3.

3 Scope of Needs Assessment

This NA covers the Niagara Region over an assessment period of 2015 to 2024. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

3.1 Niagara Region Description and Connection Configuration

For regional planning purposes, the Niagara region includes the City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-on-the-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham. Haldimand County has also been included in the regional infrastructure planning needs assessment for Niagara region. A map of the region is shown below in Figure 1.

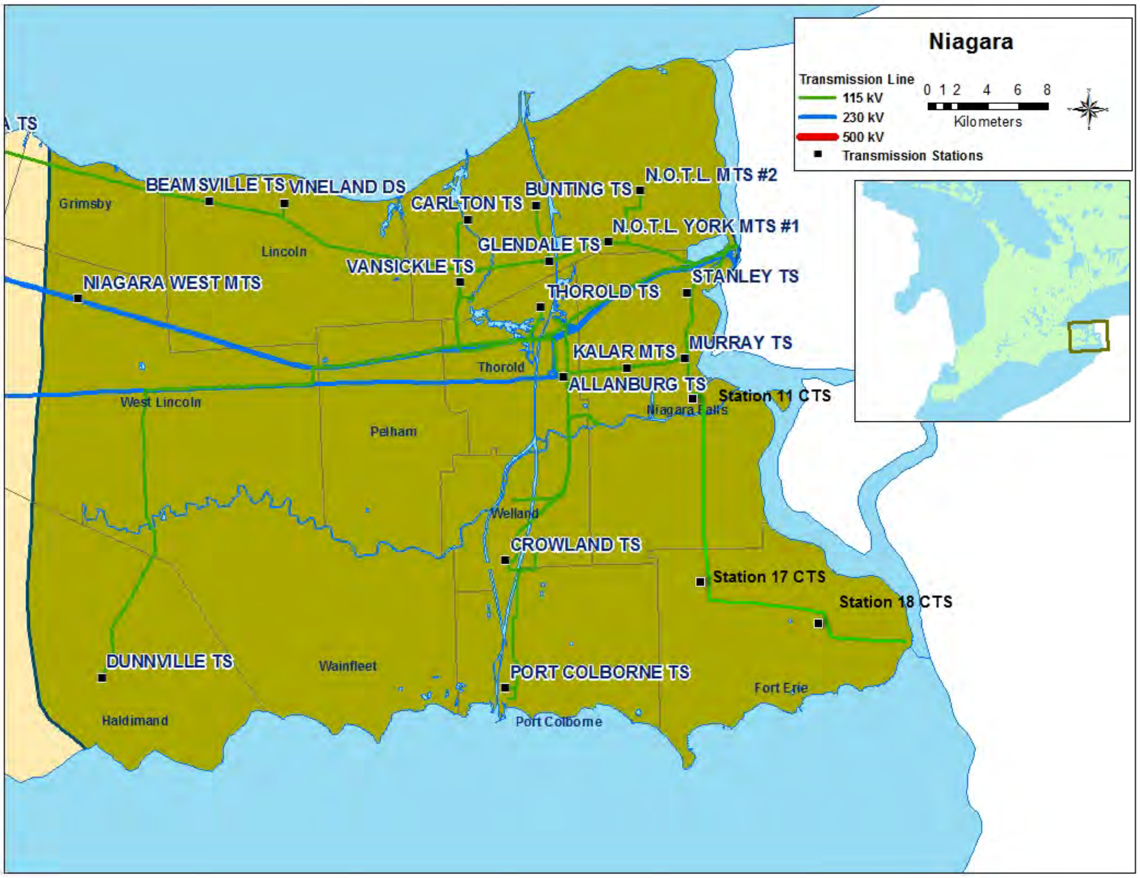

Figure 1: Niagara Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck #1, Sir Adam Beck #2, Decew Falls GS, Thorold GS and the autotransformers at Allanburg TS.

Bulk supply is provided through the 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) from Sir Adam Beck #2 SS. These circuits connect this region to Hamilton/Burlington.

The Niagara Region has the following local distribution companies (LDC):

- Canadian Niagara Power Inc.
- Grimsby Power Inc.
- Haldimand County Hydro Inc.
- Horizon Utilities
- Hydro One Distribution Inc.
- Niagara Peninsula Energy Inc.
- Niagara on the Lake Hydro Inc.
- Welland Hydro Electric System Corporation

Large transmission connected customers in the area will not actively participate in the regional planning process, however their load forecasts will used in determining regional supply needs.

Table 2: Transmission Lines and Stations in Niagara Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Customer Transformer Stations
Q3N, Q4N, Q11S, Q12S, Q2AH, A36N, A37N, D9HS, D10S, D1A, D3A, A6C, A7C,C1P, C2P	Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M, Q21P, Q22P	Allanburg TS*, Stanley TS, Niagara Murray TS, Thorold TS, Vansickle TS, Carlton TS, Glendale TS, Bunting TS, Dunville TS, Vineland TS, Beamsville TS, Sir Adam Beck SS #1, Sir Adam Beck SS #2, Crowland TS, Port Colborne TS	Niagara on the Lake #1 and #2 MTS, CNPI Station 11 , CNPI Station 17, CNPI Station 18, Kalar MTS, Niagara West MTS

Stations with Autotransformers installed

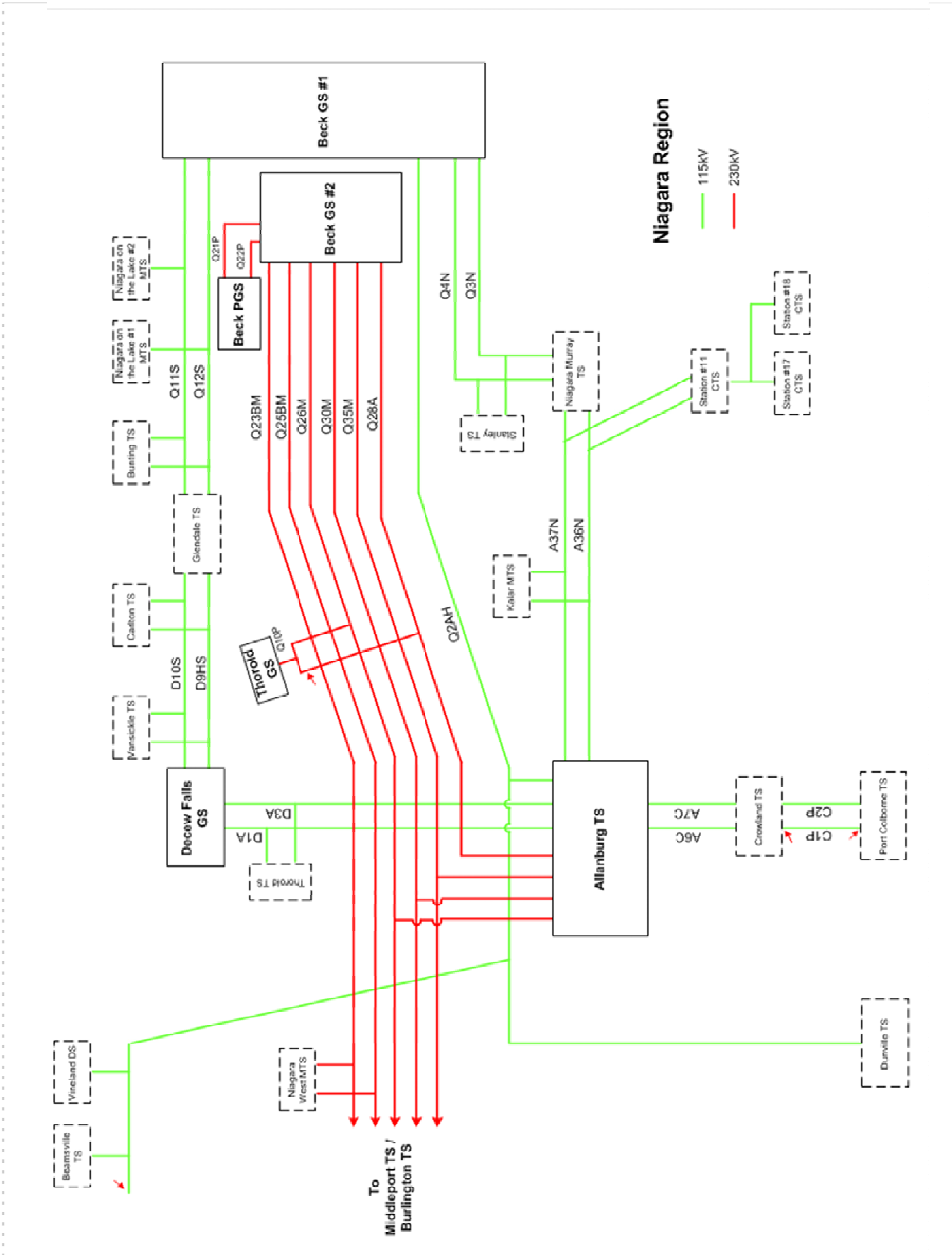

Figure 2: Simplified Niagara Regional Planning Electrical Diagram

4 Inputs and Data

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- Actual 2013 regional coincident peak load and station non-coincident peak load provided by IESO;
- Historical (2012-2014) net load and gross load forecast (2015-2024 provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by IESO;
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per the data provided by the study team, the gross load in region is expected to grow at an average rate of approximately 0.61% annually from 2015-2024.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to decrease at an average rate of approximately 0.26% annually from 2015-2024.

5 Needs Assessment Methodology

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

1. The Region is summer peaking so this assessment is based on summer peak loads.
2. Forecast loads are provided by the Region's LDCs.
3. Load data for the industrial customers in the region were assumed to be consistent with historical loads.
4. Accounting for (2), (3), above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG are analyzed to determine if the needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report.

5. Review impact of any on-going and/or planned development projects in the Region during the study period.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR). Summer LTR ratings were reviewed to assess the worst possible loading scenario from a ratings perspective.
8. Extreme weather scenario factor at 1.037 was also assessed for capacity planning over the study term.
9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their summer long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using summer loading with summer 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.

- With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 Results

6.1 Transmission Capacity Needs

230/115 kV Autotransformers

The 230/115kV transformers supplying the region are adequate for loss of single unit.

Transmission Lines & Ratings

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

The 115 kV circuits supplying the Region are adequate over the study period with Q4N as an exception between Sir Adam Beck SS #1 x Portal Junction.

230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station summer peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario.

6.2 System Reliability, Operation and Restoration

6.2.1 Load Restoration

Load restoration is adequate in the area and meet the ORTAC load restoration criteria.

The needs assessment did not identify any additional issues with meeting load restoration as per the ORTAC load restoration criteria.

6.2.2 Thermal Overloading on Q4N Section

Under high generation scenarios at Sir Adam Beck GS #1, the loading on the *Beck SS #1 x Portal Junction* section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings. Hydro One already has plans to address this issue as part of the Beck SS #1 Refurbishment Project.

6.2.3 Power Factor at Thorold TS

A few instances (<54 hours / year) of power factor below 0.9 (between 0.89 - 0.9) were observed at the HV side of Thorold TS. Hydro One Distribution will investigate these instances and work with Distribution customers to address.

7 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers and power transformers during the study period. At this time, the following sustainment work is planned at the following stations:

- DeCew Falls SS Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS; Switchgear Replacement (2020)
- Sir Adam Beck SS #2 230kV Circuit Breakers Replacement (2020)
- Glendale TS; Station Refurbishment and Reconfiguration (2021)
- Stanley TS; Station Refurbishment (2021)
- Thorold TS; Transformer Replacement (2021)
- Crowland TS; Transformer Replacement (2021)

8 Recommendations

Based on the findings and discussion in Section 6 and 7 of this report, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

9 Next Steps

No further Regional Planning is required at this time. The Niagara Region Regional Planning will be reassessed during the next planning cycle or at any time should unforeseen conditions or needs warrant to initiate the regional planning for the region.

10 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO 18-Month Outlook: March 2014 – August 2015

iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

Appendix A: Non-Coincident Winter Peak Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
NPEI - Embedded	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
Grimsby Power, NPEI - Embedded	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
Crowland TS	Net Load Forecast	89.1	93.6	74.6										
Welland Hydro	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
Hydro One, CNPI - Embedded	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Haldimand County Hydro	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
Hydro One - Embedded	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
NPEI - Embedded	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
NPEI Embedded	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
	Gross Peak Load - DG - CDM				52.1	51.7	51.5	51.1	50.8	50.5	50.4	50.3	50.3	50.2
Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland TS	Net Load Forecast	17.4	17.0	17.0										
Hydro One	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
NPEI - Embedded	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
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LOCAL PLANNING REPORT

Q4N THERMAL OVERLOAD

Region: Niagara

Revision: Final
Date: November 11th 2016

Prepared by: Niagara Region Study Team

Niagara Region Local Planning Study Team
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Canadian Niagara Power Inc.
Grimsby Power Inc.
Haldimand County Hydro Inc.
Horizon Utilities Corp.
Niagara Peninsula Energy Inc.
Niagara on the Lake Hydro Inc.
Welland Hydro Electric System Corp.

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Niagara Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Local Planning Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Local Planning Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Local Planning Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

LOCAL PLANNING EXECUTIVE SUMMARY

REGION	Niagara Region ("Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	16 May 2016	**END DATE**	1 November 2016

1. INTRODUCTION

The purpose of this Local Planning ("LP") report is to develop and recommend a preferred wires solution that will address the local needs identified in the Needs Assessment (NA) report for the Niagara Region. The development of the LP report is in accordance with the regional planning process as set out in the Planning Process Working Group ("PPWG") Report to the Ontario Energy Board's ("OEB") and mandated by the Transmission System Code ("TSC") and Distribution System Code ("DSC").

2. LOCAL NEEDS REVIEWED IN THIS REPORT

This report reviewed the potential thermal rating violation for the Beck SS #1 x Portal Junction section of the 115kV Q4N circuit (egress out from Sir Adam Beck GS #1).

3. OPTIONS CONSIDERED

The following options were considered:

- Option 1: Status Quo
- Option 2: Uprate Circuit Section

4. PREFERRED SOLUTIONS

Option 2 is the preferred option. The uprating of limiting section of the circuit is included in Hydro One's Sustainment plan.

5. RECOMMENDATIONS

It is recommended that the circuit section upgrade proceed with current with an expected in-service date of December 2019.

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LIST OF FIGURES

1 Introduction

The Needs Assessment (NA) for the Niagara Region ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. The NA for the Niagara Region was prepared jointly by the study team, including LDCs, Independent Electric System Operator (IESO) and Hydro One. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the Region over the next ten years (2015 to 2024) and recommended that they should be further assessed through the transmitter-led Local Planning (LP) process.

As part of the NA report for the Niagara Region, it identified that under high generation scenarios at Sir Adam Beck GS #1, the loading on the Beck SS #1 x Portal Junction section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings in IESO's System Impact Assessment for the Sir Adam Beck-1 GS – Conversion of units G1 and G2 to 60 Hz

This Local Planning report was prepared by Hydro One Networks Inc. ("HONI"). This report captures the results of the assessment based on information provided by LDCs and HONI.

2 Regional Description and Circuit Q4N Description

Sir Adam Beck GS #1 is an 115kV hydroelectric generating station located on the Niagara Escarpment north of Niagara Falls in Queenston. Geographically, it roughly borders Highway 405 and the Canadian-American border via the Niagara River.

Electrical supply from Sir Adam Beck GS #1 is currently provided through eight (8) OPG generators connected to Hydro One's 115kV solid 'E' bus inside the station. Supply to the local 115kV area is delivered via five (5) Hydro One circuits (Q2AH, Q3N, Q4N, Q11S, Q12S) from 115kV 'E' bus within the power house. The 115 kV 'E' bus serves as a switching station for the Hydro One network as well as a connection facility for OPGI's generators. The generators, transformers and circuits on the 'E' bus are sectionalized via switches.

A single line diagram is shown of the 115 kV system originating from the 115kV Sir Adam Beck GS #1 in Figure 1.

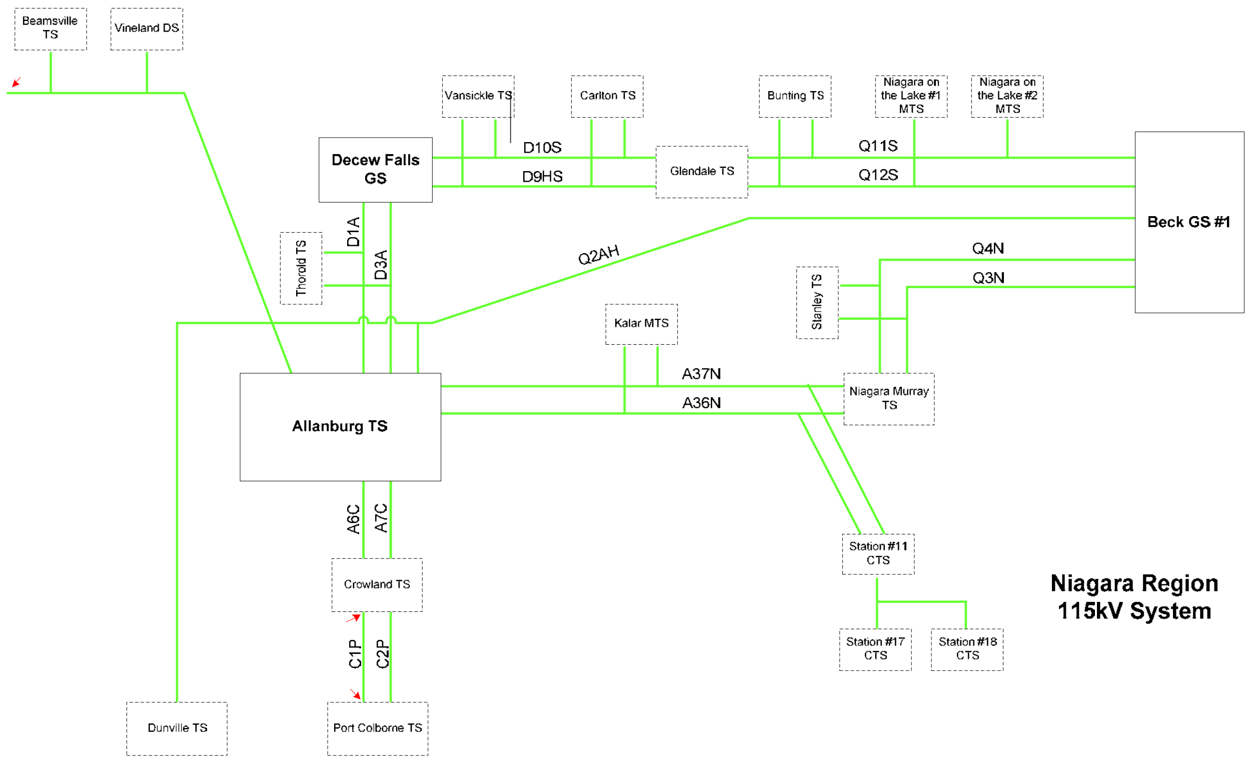

Figure 1: Single Line Diagram – Niagara Region 115kV System

From the NA report for the Niagara Region, a possible thermal limit issue on a section of the circuit Q4N was identified. Q4N is an approximately 9 km long, 115kV radial circuit from Sir Adam Beck GS #1, supplying Stanley TS and Niagara Murray TS.

The section of Q4N identified in the NA comprises of the section from Sir Adam Beck GS #1 to Portal Junction. This section of circuit is shown in Figure 2.

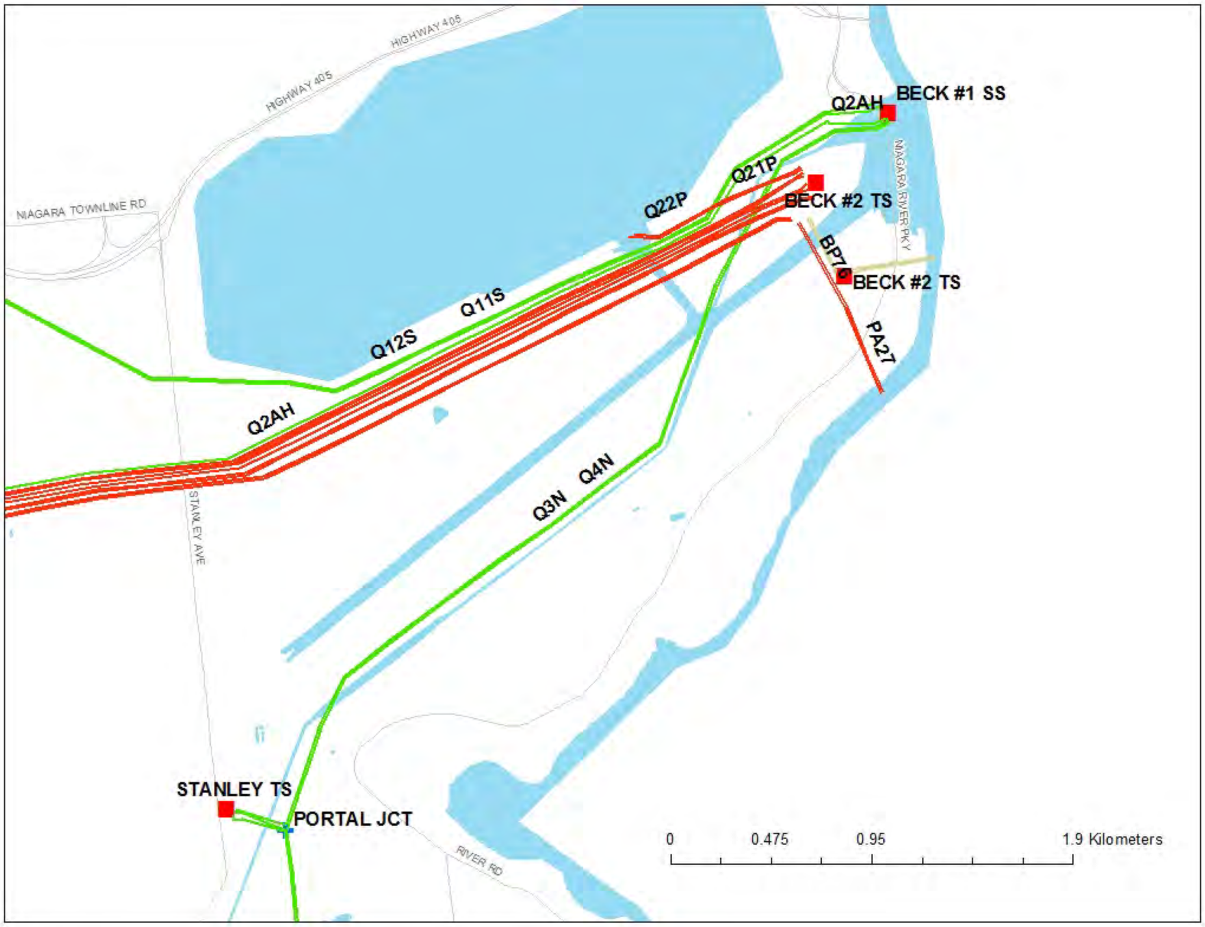

Figure 2: Single Line Diagram – Q4N from Beck #1 SS to Portal Junction

3 Local Niagara Need (Q4N)

In the past decade, OPG has been steadily increasing the power output of their generators with station upgrades.

In the IESO SIA for "Sir Adam Beck-1 GS – Conversion of units G1 and G2 to 60 Hz" it was identified that the thermal loading on circuit section Q4N from Beck #1 SS to Portal junction exceeds its continuous rating by 109.6% at total generation output of Sir Adam Beck #1 GS. This study was based on 2018 summer peak demand with high generation dispatch in the 115 kV transmission system in the vicinity with the existing 8 generators and 2 future generators (G1 and G2) at full output. This thermal loading is based on an ambient 35ºC temperature condition with 4 km/hr wind speed during daytime.

Reducing the generation output of Sir Adam Beck #1 GS from its maximum capacity of 556 MW to 509 MW reduces the loading on Q4N (Beck #1 SS by Portal Junction) to below its continuous rating.

4 Study Result / Options Considered

The conductor on a 64m section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal Jct. is comprised of 605.0 kcmil aluminum, 54/7 ACSR. The continuous rating for this type of conductor at 93^{o}C is 680A. The options considered are outlined below.

4.1 Option 1: Status Quo

Status Quo is not an option because there is a risk that for maximum generation dispatch in extreme weather conditions. Under these conditions generation would have to be curtailed to meet line thermal rating requirements and thus causing financial losses to customer.

4.2 Option 2: Uprate Conductor Section

Hydro One has plans already in place to replace the existing section of conductor with a 910A continuous rated conductor at 93^{o}C as part of their Beck #1 SS Refurbishment project. This will enable this section of circuit to meet all pre and post contingency thermal limits during max generation and under extreme weather conditions.

5 Recommendations

It is recommended that Hydro One continues with their sustainment plans (Option 2) on replacing the section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal Jct. with a larger ampacity conductor (increase of 680A to 910A).

The expected in-service date for this conduction section upgrade is December 2019.

6 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
iii) Needs Assessment Report Niagara Region

Appendix A: Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One, NPEI - Embedded	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One & NPEI, Grimsby Power, NPEI - Embedded	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
Crowland TS	Net Load Forecast	89.1	93.6	74.6										
Welland Hydro & Hydro One, CNPI - Embedded	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Hydro One	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One & NPEI	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power, NPEI Embedded	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
	Gross Peak Load - DG - CDM				52.1	51.7	51.5	51.1	50.8	50.5	50.4	50.3	50.3	50.2
Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland DS	Net Load Forecast	17.4	17.0	17.0										
Hydro One, NPEI - Embedded	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Topic:	Regional Planning		
Date of Meeting:	April 15 2016	**Location:**	Horizon Utilities – Niagara
Subject:	Niagara Needs Assessment Review		
Written By:	Gene Ng		

Dial-in Phone Numbers: **416-883-0133** Toronto **1-877-385-4099** Toll Free (Canada & USA)	Participant Access code: **5634862 #**

Description
The purpose of this meeting is to meet face to face with the local distribution companies and review the draft Niagara Needs Assessment Report.

		Item	**Action**
1	Needs Screening Results	• Verify load forecast in spreadsheet • Include all stations in geographical map • Verify 10 year load growth • Remove NOTL restoration time, no longer an issue as station was upgraded • Remove Thorold power factor correction, LDC can fix power factor • Include I/S Dates in future Sustainment Projects • Include blurb stating local restoration meets all ORTAC requirements (time and MW requirements)	• All • Gene • Gene, Megan • Gene • Gene • Gene • Gene
2	Other Comments	• Verify possibility of re-energizing C1P • Verify possibility of Beamsville DESN double circuit supply • Provide performance history for Q2AH circuit, verify it meets criteria	• Gene
3	Next Step	• Provide draft copy for review to group	• Gene

Present / Attendees:		
NAME	**Company Department**	**Email**
Gene Ng	Hydro One TX System Development	gene.ng@HydroOne.com
Helen Guo	Hydro One DX System Development	Helen.guo@HydroOne.com
Megan Lund	IESO Transmission Integration	Megan.lund@ieso.ca
Wes Lemstra	Haldimand County Hydro	wlemstra@hchydro.ca
Hassan Syed	Niagara On the Lake Hydro	hsyed@notlhydro.com
Richard Bassindale	Horizon Utilities	Richard.bassindale@horizonutilities.com
Rosso Parra	Grimsby Power Engineering	rossop@grimsbypower.com
Shanon Wilson	Niagara Peninsula Energy	shanonwilson@npei.ca
Dan Sebert	Niagara Peninsula Energy	Dan.sebert@npei.ca
Farooq Qureshy	Hydro One Transmission Planning	Farooq.qureshy@hydroone.com
Kevin Bailey	Welland Hydro	kbailey@wellandhydro.com
On the Phone:		
Bruce Parker	Hydro One	Bruce.parker@HydroOne.com
Ajay Garg	Hydro One	Ajay.garg@hydroone.com
Kevin Kilfoil	Canadian Niagara Power Inc.	kevin.kilfoil@FortisOntario.com
Phillip Woo	IESO	Phillip.woo@IESO.ca

KEY ACCOUNT MANAGEMENT

MINUTES OF MEETING

MEETING TITLE: Niagara LDC Meeting

MEETING OBJECTIVE: face-to-face discussions with all LDC in Niagara Region, on future plans, load growth and potential issues in the Niagara Region.

Date/Time: July 4th, 2019 9:30am- 2pm
Author of Minutes: Gene Ng
Location: Holiday Inn – St.Catharines
Dial-In: In-person only

ATTENDEES: See last page

AGENDA

1. Hydro One to present upcoming projects, load growth, overview of Niagara Region and Regional Planning Process (see attached powerpoint slides)
2. LDC's to present load growth, projects etc in their service territory

NOTES:

	LDC Update
Alectra Utilities	No substantial growth expected in the region.
CNPI	No substantial growth expected in the region.
Grimsby Power	Beamsville TS: additional loading (7.5MW in 2019, 6.3MW in 2020) - Possible action is to add additional feeder from Niagara West MTS - Possible additional 15-25MW of further additional growth in future
NPEI	Beamsville TS: anticipate residential growth Possible hospital in 2025 – requires 2 feeders (1 from Murray TS, 1 for Kalar TS)
Welland Hydro	Crowland TS – anticipate residential growth Load forecast was provided (powerpoint presentation)

	Description	Owner	Timing	Comments
1	Provide load forecast at earliest convenience, especially for Beamsville TS	All LDC (Welland Hydro already provided	Sept 1 2019	
2	Provide to All LDCs :Letter for meeting with Hydro One for OEB purposes	Gene Ng/Stefanie Pierre	July 31 2019	
3	Terms of Reference for future meetings	Stefanie Pierre	Aug 31 2019	
4	Provide to Grimsby Power 1) response to Niagara West MTS outage, and possible backup solutions 2) contact for Beamsville TS M4 feeder egress discussion (line assessment etc)	Melody More/Stefanie Pierre	July 31 2019	
5	Provide to NPEI 1) Information about future plans for Murray TS. Initial discussion on schematic	Gene Ng/Stefanie Pierre		*discussions are being intitiated internally for this project
6	Provide Welland Hydro 1) future Crowland TS plans for discussion 2) Possibility of utilizing idle circuit in the area to separate A6C/A7C from common tower	Gene Ng/Stefanie Pierre		

Attendees			
	Name	**Company**	**Department / Role**
1	Stefanie Pierre	Hydro One	Account Executive
2	Melody More	Hydro One	Large Customer Operating Support
3	David Molyneaux	Hydro One	Operating Planning
4	Lukito Adiputra	Hydro One	Regional Planning
5	Gene Ng	Hydro One	System Development
6	Daniel Lawerence	Alectra	Planning Engineer, Asset Management
7	Don Gilbert	Canadian Niagara Power	Regional Manager
8	Rosso Parra	Grimsby Power	Engineering Supervisor
9	Kevin Carver	Welland Hydro	Sr.Electrical Distribution System Engineer
10	Kevin Bailey	Welland Hydro	Director of Engineering and Operations
11	Shanon Wilson	Niagara Pennisula Energy Inc	Sr. VP of Asset Management
12	Jim Sorely	Niagara Pennisula Energy Inc	Director of Engineering
13	Kazi Marouf**	Niagara on the Lake Hydro	VP, Operations
14	Tim Curtis**	Niagara on the Lake Hydro	President
15			

**Sent their regrets

Appendix D:
REG Investment Plan

From: Miriam Heinz [mailto:Miriam.Heinz@ieso.ca]
Sent: Wednesday, October 23, 2019 12:25 PM
To: Jim Sorley
Cc: Bryan Timm
Subject: FW: Niagara Peninsula Energy : REG Investment Plan - IESO Comment Letter

Good morning Jim. I am replying to your request to the IESO of October 18, 2019.

In review of Niagara Peninsula Energy Inc.'s (NPEI) Renewable Energy Generation (REG) Investment Plan, the IESO notes that NPEI is not proposing any capital investments for grid constraint mitigation or for capacity upgrades to facilitate the connection of REG for the period 2019/2020 to 2025.

In the case where a distributor has no REG investments during the 5-year Distribution System Plan (DSP) period no letter from the IESO is required, as the requirement is for when there *are* investments.

To illustrate this, provided below is an excerpt from the Ontario Energy Board's **Filing Requirements For Electricity Distribution Rate Applications** - Chapter 5, section 5.2.2 Coordinated planning with third parties:

d) For REG investments a distributor is expected to provide the comment letter provided by the IESO in relation to REG investments included in the distributor's DSP, along with any written response to the letter from the distributor, if applicable. The OEB expects that the IESO comment letter will include:

- *Whether the distributor has consulted with the IESO, or participated in planning meetings with the IESO;*
- *The potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and*
- *Whether the REG investments proposed in the DSP are consistent with any Regional Infrastructure Plan.*

The IESO appreciates having had the opportunity to review NPEI's REG Investment Plan. Should you wish to discuss further or have any questions, please contact us again.

Kind regards,
Miriam

Miriam Heinz | Advisor, Regulatory Affairs
Independent Electricity System Operator (IESO) | T: (416) 969-6045 | C: (416) 917-3617
1600-120 Adelaide Street West, Suite 1600, Toronto, ON, M5H 1T1

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Web: www.ieso.ca | Twitter: IESO Tweets | LinkedIn: IESO

Renewable Energy Generation Investment Plan

Per: OEB Chapter 5 Consolidated Distribution System Plan
Filling Requirements – 5.2.2 (d)

June 21, 2019

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Executive Summary

Niagara Peninsula Energy Inc. (NPEI) has developed a Renewable Energy Generation (REG) Investment Plan to provide to the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO). The purpose of the plan is to outline NPEI's ability to connect Distributed Generation (DG) systems to its distribution system as well as determine any investments required to accommodate these connections over the next five years.

NPEI currently has 459 MicroFIT, 23 FIT, 2 load displacement, 33 net metering and 1 CHP systems connected to the distribution system, representing a total of 21.5MW of potential generation. NPEI forecasts that there will be 120 new generation connections over the next 7 years, adding 8.1MW of combined generation. The amount of new generation connections is expected to decrease in 2019 due to the cancellation of the MicroFIT and FIT programs. Customers will shift their focus to NET metering, and alternate DER projects, but adoption may be guarded temporarily as the electrical energy market is going through a period of transformation.

NPEI's distribution system is constantly monitored to ensure the ability to connect renewable energy generation to the grid. NPEI does not currently see a need for immediate investment to accommodate generator connections, but is prepared to add items to our long term budget if there are unforeseen changes on specific feeders, causing investment to be required.

Introduction

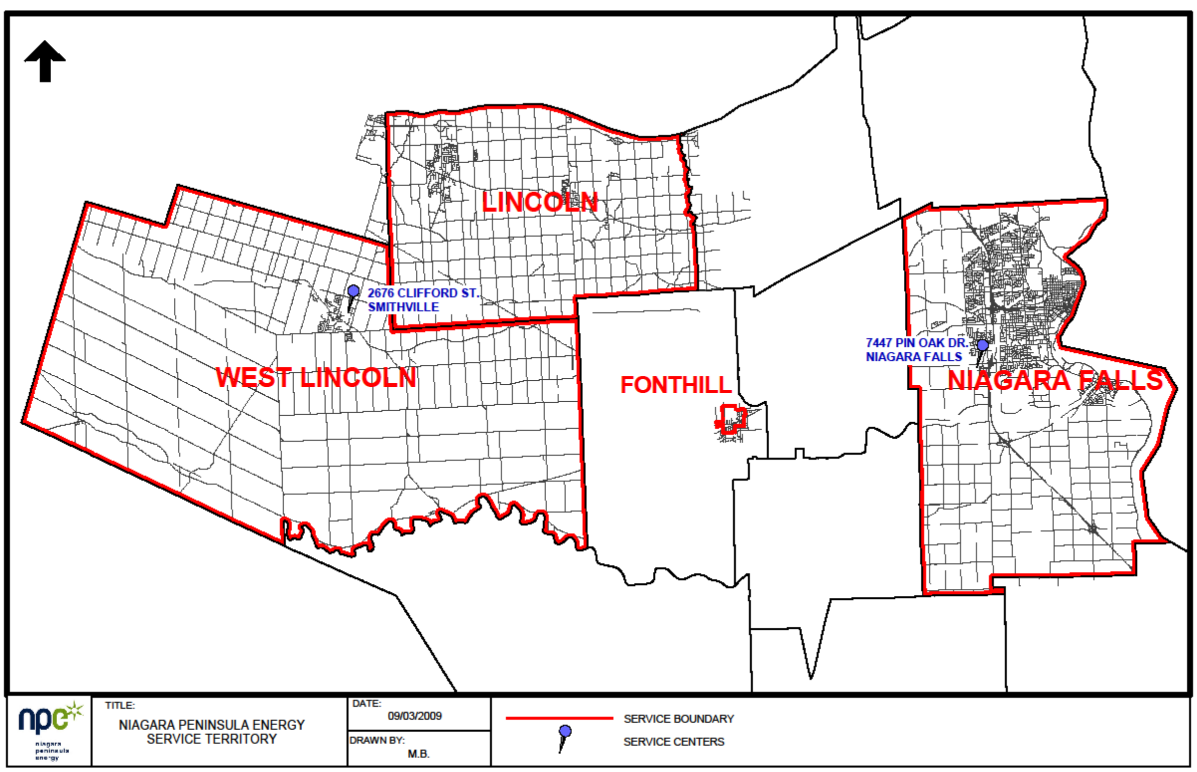
In accordance with the Ontario Energy Board's (OEB) filing requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan filing Requirements, NPEI has prepared the following Renewable Energy Generation (REG) Investment Plan. The REG Investment plan details the readiness of NPEI's distribution system to accommodate the connection of renewable energy generation facilities and details any expansion or enhancements necessary to remove grid constraints for the period 2020 to 2025.

NPEI System Overview

Niagara Peninsula Energy Inc (NPEI) provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham and Township of West Lincoln. NPEI is governed by an eight member Board of Directors.

Niagara Peninsula Energy Inc is jointly owned by Niagara Falls Holding Corporation and Peninsula West Power Inc. Niagara Falls Holding Corp. is wholly owned by the City of Niagara Falls. Peninsula West Power Inc., which is also a Holding Company, is jointly owned by the Town of Lincoln, the Town of Pelham and the Township of West Lincoln.

NPEI's service territory is a mixture of urban and rural, covering approximately 827 square kilometers.



NPEI receives power from 5 transformer stations owned by Hydro One Networks Inc. (HONI) as well as 1 transformer station that is owned by NPEI and one that is owned by Grimsby Power Inc. (GPI). NPEI owns 10 municipal transformer stations in the City of Niagara Falls, 5 distribution stations which serves NPEI's distribution system in the Town of Lincoln, Town of Pelham and Township of West Lincoln. NPEI also receives power from one HONI owned distribution station in West Lincoln. Table 1 summarizes the transformer stations supplying NPEI as well as the number of feeders from each station.

Transformer Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Murray TS	Hydro One	115kV	13.8kV	16
Kalar TS	Niagara Peninsula Energy	115kV	13.8kV	8
Stanley TS	Hydro One	115kV	13.8kV	10
Beamsville TS	Hydro One	115kV	27.6kV	4
Niagara West TS	Grimsby Power Inc.	230kV	27.6kV	3
Vineland DS	Hydro One	115kV	27.6kV	2
Allanburg TS	Hydro One	115kV	27.6kV	2

Table 1: Summary of Transformer Stations

Present Levels of Distributed Generation Connections

NPEI has connected more than 500 generators, totaling over 21MW of potential generation to the distribution system which is summarized in table 2 below:

Station	Bus Name	Feeders	NUG		FIT		MicroFit		Net Metering		CHP		LD		Total	
			Count	kW	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW
Murray	QZ	M51, M52, M53, M54, M55, M56	0	0.0	0	0.0	37	358.0	2	13.0	0	0.0	0	0.0	39	371.0
Murray	Y1Y2	M25, M26, M27, M28, M29, M30	0	0.0	0	0.0	8	76.0	1	4.0	0	0.0	0	0.0	9	80.0
Murray	J	M10, M11, M13	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Murray	K	M14, M15, M16, M17, M18	0	0.0	1	75.0	7	70.0	1	5.0	0	0.0	0	0.0	9	150.0
Kalar	BY	KM1, KM2, KM3, KM4, KM5, KM6,	0	0.0	1	1000.0	71	682.0	2	25.0	0	0.0	0	0.0	74	1707.0
Stanley	BY	M1, M2, M3, M4, M5,	0	0.0	3	370.0	10	94.0	0	0.0	0	0.0	1	35.0	14	499.0
Stanley	QJ	M31, M32, M33,	0	0.0	0	0.0	36	352.0	1	10.0	0	0.0	0	0.0	37	362.0
Beamsville	BY	M1, M2, M3, M4	0	0.0	9	1940.0	122	1183.0	9	172.0	0	0.0	0	0.0	140	3295.0
NWTS	BY	M2, M3, M4, M5	0	0.0	5	9790.0	56	539.0	14	183.0	1	2731.0	0	0.0	76	13243.0
Vineland	T1	F1	0	0.0	2	500.0	69	651.0	2	11.0	0	0.0	1	160.0	74	1322.0
Vineland	T2	F2	1	300.0	2	75.0	34	335.0	0	0.0	0	0.0	0	0.0	36	410.0
Allanburg	BY	M6, M7, M8	0	0.0	0	0.0	9	89.0	1	5.0	0	0.0	0	0.0	10	94.0
Total			**1**	**300.0**	**23**	**13750.0**	**459**	**4429.0**	**33**	**428.0**	**1**	**2731.0**	**2**	**195.0**	**518**	**21533.0**

Table 2: Summary of Existing Connected Generation

Present Capacity for the Connection of Distributed Generation

NPEI has done an assessment to determine the amount of generation that can be connected to the distribution system. It is imperative that the addition of new generation does not damage distribution equipment or create safety concerns due to short circuit conditions. Equipment must also be rated to meet the thermal capacity requirements of the system at all times, so as to minimize line losses and to reduce the risk of premature failure of equipment. All generation that is connected to NPEI's system must be equipped with anti-islanding and protections schemes, which ensures that generators do not create islanding situations, which may cause damage to equipment during outages. Large generators operating in parallel with the distribution system are required to install transfer-trip as per Hydro One's TIR.

Distribution System DG Capacity Assessment

The following table summarizes the available capacity at all of the transformer stations in NPEI's distribution territory as well as the connected generation.

Station	Bus Name	Feeders	Voltage (kV)	SC Cap. (MVA)	Thermal Cap. (kW)	Existing DG Non-Renew	Esisting DG Renewable	Remaining Capacity
Murray	QZ	M51, M52, M53, M54, M55, M56	13.8	84.7	1200	0.0	371	829.0
Murray	Y1Y2	M25, M26, M27, M28, M29, M30	13.8	88.9	1240	0.0	80	1160.0
Murray	J	M10, M11, M13	13.8	119.3	1400	0.0	0	1400.0
Murray	K	M14, M15, M16, M17, M18	13.8	119.3	9400	0.0	150	9250.0
Kalar	BY	KM1, KM2, KM3, KM4, KM5, KM6, KM7, KM8	13.8	17.6	11000	0.0	1707	9293.0
Stanley	BY	M1, M2, M3, M4, M5, M6	13.8	68.3	7100	35.0	464	6636.0
Stanley	QJ	M31, M32, M33, M41, M42, M43	13.8	15.2	10300	0.0	362	9938.0
Beamsville	BY	M1, M2, M3, M4	27.6	372.9	32400	0.0	3295	29105.0
NWTS	BY	M2, M3, M4, M5	27.6	113.7	15000	2731.0	10512	4488.0
Vineland	T1	F1	27.6	431.3	14500	160.0	1162	13338.0
Vineland	T2	F2	27.6	430.4	14500	300.0	110	14390.0
Allanburg	BY	M6, M7, M8	27.6	59.6	24800	0.0	94	24706.0
Total					**142840.0**	**3226.0**	**18307**	**124533.0**

Table 3: Summary of Available DG Capacity at Transformer Stations

Historical Renewable Generation Growth

Between 2009 and Dec. 31st 2018, NPEI connected 516 generation projects. The majority of Renewable Generation installations in NPEI's service area consist mainly of rooftop solar PV projects smaller than 250kW, however, there is one 9MW wind generation connection. Table 4 below summarizes the REG connections on NPEI's distribution system between 2009 and 2018.

Year	FIT		MicroFit		Net Metering		CHP		LD		Total	
	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW
2009	1	250.0	0	0.0	3	12.9	0	0.0	0	0.0	4	262.9
2010	2	283.0	52	497.3	0	0.0	0	0.0	0	0.0	54	780.3
2011	3	313.5	114	1057.4	1	10.6	0	0.0	0	0.0	118	1381.5
2012	3	338.0	52	435.3	4	34.8	0	0.0	0	0.0	59	808.1
2013	2	325.0	71	630.4	1	2.6	0	0.0	0	0.0	74	958.0
2014	3	9250.0	39	354.9	2	7.2	0	0.0	0	0.0	44	9612.1
2015	2	500.0	59	526.0	6	18.5	0	0.0	0	0.0	67	1044.5
2016	0	0.0	17	142.0	5	49.3	0	0.0	1	35.0	23	226.3
2017	0	0.0	45	369.3	5	102.4	1	2731.0	1	160.0	52	3362.7
2018	7	1540.0	10	90.0	4	31.0	0	0.0	0	0.0	21	1661.0
Total	**23**	**12799.5**	**459**	**4102.6**	**31**	**269.3**	**1**	**2731.0**	**2**	**195.0**	**516**	**20097.4**

Table 4: Summary of Connected Generation Growth to Date

Projected Renewable Generation Growth

With the elimination of the FIT and MicroFIT programs, NPEI has already seen a decrease in the number of distributed generation projects. Projects have shifted to net metering, load displacement and CHP/cogen projects. Based on connection and application activity over the months since the MicroFIT program has ended, NPEI anticipates a small decrease in distributed generation connections in 2019 and 2020. We have seen an increase in enquiries relating to energy storage and load displacement projects, though preliminary proposed project timelines would indicate the connections would be scattered over the next few years. NPEI's forecast for 2019 to 2025 can be seen in Table 5.

Year	FIT		MicroFit		Net Metering		CHP		LD		Total	
	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW
2019	0	0.0	0	0.0	15	304.2	0	0.0	1	1000.0	16	1304.2
2020	0	0.0	0	0.0	15	299.0	0	0.0	1	995.0	16	1294.0
2021	0	0.0	0	0.0	16	308.0	0	0.0	2	2000.0	18	2308.0
2022	0	0.0	0	0.0	16	308.0	0	0.0	0	0.0	16	308.0
2023	0	0.0	0	0.0	17	317.0	0	0.0	1	1000.0	18	1317.0
2024	0	0.0	0	0.0	17	317.0	0	0.0	0	0.0	17	317.0
2025	0	0.0	0	0.0	18	326.0	0	0.0	1	1000.0	19	1326.0
Total	**0**	**0.0**	**0**	**0.0**	**114**	**2179.2**	**0**	**0.0**	**6**	**5995.0**	**120**	**8174.2**

Table 5: Projected Renewable Generation Growth

<u>**Notes**</u>

1 Net meter count and kW for 2019 are based on actual connected and projected for the remainder of the year.

2 Net metering count beyond 2019 is based on 3% growth per year.

3 Net metering kW calculation beyond 2019 is done as follows:

(4 > 10kW projects at an average of 50kW) + (Remainder of projects < 10 kW at an average of 9 kW)

4 Load displacement projects for 2019 = 1MW, 2020 = 995Kw, 2021 = 1MW x 2

5 Load displacement projects beyond 2021 are an estimation of 1 project @ 1MW every other year

Investments to Facilitate Renewable Energy Generation

NPEI is committed to investments related to connecting renewable energy generation if it is required. NPEI has reviewed the need for capital and OM&A expenditures for the purpose of expanding the distribution system to enable future REG connections. Based on historical trends and anticipated future REG connections, no expenditure is anticipated between 2019 and 2025 that will be required for constructing feeder assets to specifically accommodate renewable energy connections.

NPEI will be continuously monitoring whether additional investments need to take place so REG can be connected to the system.

Appendix E:
Customer Engagement Reports

Customer Engagement

2021-2025 Rate Application

January 2020

Prepared for:

Niagara Peninsula Energy Inc.
7447 Pin Oak Drive
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Customer Engagement Overview

January 2020

Confidentiality

This Overview and all the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Niagara Peninsula Energy Inc. ("Niagara Peninsula Energy" or "NPEI").

Acknowledgement

This Overview has been prepared by Innovative Research Group Inc. ("INNOVATIVE") for Niagara Peninsula Energy Inc. The conclusions drawn, and opinions expressed are those of the authors.

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Introduction

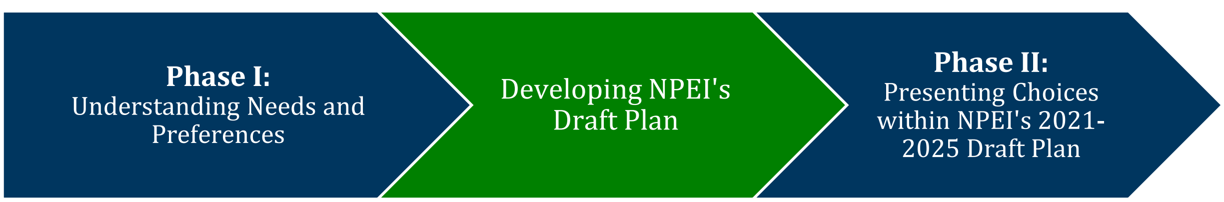
In May 2019, Innovative Research Group Inc. (INNOVATIVE) was engaged by Niagara Peninsula Energy to assist in meeting the utility's customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors (RRFE).

Niagara Peninsula Energy is in the process of developing its 2021-2025 rate application and set out to gather meaningful feedback from its customers, specifically when it comes to their needs, the outcomes important to them, and their preferences regarding the pacing and prioritization of specific investments.

Between June and December 2019, Niagara Peninsula Energy gathered feedback from more than 3,000 residential, small business and commercial customers through its customer engagement efforts - in context, Niagara Peninsula Energy, through INNOVATIVE, engaged with nearly 6% of its entire customer base.

Throughout this customer engagement, a concerted effort was made to ensure that all customers – regardless of where they live or operate, or how much electricity they use - had an equal opportunity to participate, whether through voluntary or random sampling. In order to facilitate the collection of this robust feedback, INNOVATIVE and NPEI developed a two-phased approach which was both iterative and responsive at each stage of feedback.

Undertaking a two-phased approach also enabled NPEI a clear opportunity to demonstrate how customer feedback collected in Phase I was incorporated into the utility's draft plans, and will enable them to clearly respond to actionable feedback gathered in Phase II. Incorporating customer feedback into NPEI's plans was a key objective of this customer engagement, and this two-phased approach helped facilitate its achievement.



This document contains the results of both phases of customer engagement, with a focus on the generalizable results of the representative sample from Phase II.

Customer Engagement Key Findings

Phase I: Understanding Needs and Preferences

The first phase of NPEI's 2019 customer engagement look place between **June and July 2019** with a series of focus groups, and telephone and online surveys.

The purpose of this initial phase of engagement was to provide NPEI planners with input on customers' needs and preferences as they relate to the outcomes and goals that the utility should focus on over the 2021-2025 period; as well as develop a detailed understanding of the differences between customers with known email addresses (email sample) and the broader customer base (telephone sample).

This initial phase of engagement was conducted at the beginning of NPEI's planning cycle in order to ensure that the draft plan distinctly took into consideration the views of customers.

In June 2019, an initial round of four exploratory focus groups were conducted amongst residential and small business customers in both Niagara Falls and West Lincoln. One primary objective of these groups was to obtain insights into what customers expect of NPEI, what are their priorities, both in context of valued outcomes, and the investment choices impacting customers that the utility will need to make.

NPEI's customer engagement was an iterative process, wherein each phase and activity informed the next. The results of these exploratory focus groups (see **Appendix 1.0** for summary), played an important role in informing the questions that were asked in a subsequent series of telephone and online surveys.

In addition to OEB direction on LDC rate application filings contained in the RRFE, its Handbook for Utility Rate Applications notes the following: *"The OEB expects a utility's rate application to provide an overview of customer needs, preferences and expectations learned through the utility's customer engagement activities*."[1] This section provides an overview of customer needs, preferences and expectations as gathered through parallel online and telephone surveys. Full results can be found in **Appendix 2.0**.

Customer Needs

Needs questions focus on understanding the gap between the services and experience customers want and the services and experience customers are receiving.

In the initial exploratory focus groups, participants noted that they were satisfied with the services they receive from NPEI, including both customer service and, the level of reliability they experience.

[1] Handbook for Utility Rate Applications, p. 12 (October 13, 2016)

Overall Satisfaction with Niagara Peninsula Energy

The Phase I surveys confirmed that most residential and small business customers are satisfied with the level of service that NPEI provides.

Phase I Telephone Reference Survey	Residential	Small Business
Satisfied	89%	87%
Dissatisfied	6%	3%

What can NPEI do to improve services?

Looking beyond topline customer satisfaction, to uncover whether there is a gap between the services and experience customers want and what they are receiving, we asked what NPEI could do, if anything, to improve services.

In the exploratory focus groups, many customers felt that the price of electricity was the central area where NPEI could improve service. That said, very few had an initial understanding of NPEI's role in the electricity system, including the portion of their bill that is remitted to the utility. Additionally, some customers felt that there was a lack of customer education regarding the system as a whole, with particular emphasis on helping customers reduce their electricity bills.

In the Phase I telephone survey, the majority of residential and small business customers noted that they either didn't know how services could improved or expressed that there was nothing in particular that the utility could do to improve service. Similar to the focus groups, about 1-in-5 customers noted that the NPEI could improve services by reducing rates.

Phase I Telephone Reference Survey	Residential	Small Business
1st	*Don't know* (30%)	*Don't know* (35%)
2nd	*None* (24%)	*Lower/Reduce rates* (21%)
3rd	*Lower/Reduce rates* (22%)	*None* (15%)

The combination of high levels of satisfaction, as well as a majority of customers not indicating how NPEI can improve services, leads to conclusion that the utility is meeting current customer needs.

Customer Preferences

Preference questions focus on customer views on the outcomes the utility should focus on, priorities among those outcomes, and trade-offs as illustrated by choices on specific programs or the pacing and prioritization of investments.

One of the objectives of the exploratory focus groups was to develop a list of outcomes/goals that NPEI should focus on in its upcoming rate application. Upon building this list with qualitative customer feedback, the Phase I surveys focused on confirming whether this list was exhaustive, in addition to quantifying customer preferences to the broader customer base.

This list featured seven outcomes /goals:

- *Ensuring reliable electrical service*

- *Delivering electricity at reasonable distribution rates*
- *Providing quality customer service and enhanced communications*
- *Proactively replacing aging infrastructure that is beyond its useful life*
- *Finding internal efficiencies and ways to find cost savings*
- *Upgrading the electrical system to better respond to and withstand the impact of adverse weather and climate change*
- *Providing tools and services that allow customers to better manage their electricity usage*

Based on the generalizable feedback from the Phase I telephone surveys, customers don't expect NPEI to just focus on one outcome. In fact, the majority of both residential and small business customers feel that almost all of the identified outcomes are *extremely important* (with the exception of providing tools to better manage electricity).

What outcomes do customers prioritize?

Among competing outcomes, *price*, *reliability*, and *finding internal cost efficiencies* are the top three priorities for both residential and small business customers. When ranked relative to other priorities, NPEI customers see price as the top outcome that the utility should focus on.

Telephone Survey	**Phase I Telephone Reference Survey**	
	Residential	Small Business
Top Priority	*Delivering electricity at reasonable distribution rates*	*Delivering electricity at reasonable distribution rates*
2nd Priority	*Ensuring reliable electrical service*	*Ensuring reliable electrical service*
3rd Priority	*Finding internal efficiencies and ways to find cost savings*	*Finding internal efficiencies and ways to find cost savings*

What reliability outcomes do customers prioritize?

Beyond the priority of ensuring reliability electrical service, customers were asked which aspect of the reliability outcome NPEI should focus on. *Reducing the overall number of outages*, the *overall length of outages*, and *improving restoration times* are the top three priorities for both rate classes.

Telephone Survey	**Phase I Telephone Reference Survey**	
	Residential	Small Business
Top Priority	*Reducing the overall number of outages*	*Reducing the overall number of outages*
2nd Priority	*Reducing the overall length of outages*	*Reducing the overall length of outages*
3rd Priority	*Reducing the length of time to restore power during extreme weather events*	*Reducing the length of time to restore power during extreme weather events*

What investment trade-offs do customers value most?

Beyond developing an understanding of the needs and outcomes that customers prioritize, the Phase I surveys also explored general trade-offs between several types of investments and cost.

These questions were intended to provide preliminary input for NPEI in putting together their initial draft plan.

In fact, the results from these surveys were summarized in the *"Customer Engagement: Needs and Preferences Planning Placemat"* (see **Appendix 3.0**) The *Planning Placemat* provided a high-level summary of the findings from the Phase I surveys, including both needs and preferences. It was shared with NPEI planners and helped ensure that customer feedback was brought into the planning process in the early stages.

Replacing Aging Infrastructure (System Renewal)

While keeping prices at a reasonable and affordable level is an important priority for customers, the majority feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Phase I Telephone Reference Survey	Residential	Small Business
Invest what it takes to maintain reliability	62%	64%
Defer investments to lessen bill impacts	26%	19%

Proactive Investments in Grid Modernization (New Technology)

The majority of residential and small business customers are willing to consider paying more to invest in maintaining reliability, equipping staff with equipment and IT systems. Knowing that it could eventually save money, they supported proactively investing in system capacity, and modernizing the grid.

Further, the majority of customers support proactive investment in both system capacity and grid modernization. Relative to other trade-offs, support for investment in system capacity is least intense.

Phase I Telephone Reference Survey	Residential	Small Business
Make proactive investments	62%	55%
Make investment prioritizing lowest cost	25%	21%

Using the input from the Phase I customer engagement, NPEI planners developed a draft plan that included an estimated baseline cost and identified a number of investment areas where pacing could be accelerated, or slowed down, in order to align with customer needs and expectations.

The Phase II customer engagement focused on presenting these investment trade-offs to customers and gathering feedback on NPEI's draft plan. The next section will summarize the findings from these activities.

Phase II: Introduction

The second phase of NPEI's customer engagement focused on customer preferences on pacing and balancing outcomes. In order to obtain this feedback, an online "workbook" was deployed to all customers with an email address on file, as well as promoted through a generic link on NPEI's website and social media platforms.

This workbook was designed to both educate customers on NPEI's role in the electricity system and its draft business plans, as well as to gather feedback on trade-offs between seven specific investments.

Prior to developing this customer engagement workbook, NPEI staff used customer feedback, collected throughout the Phase I engagement, to help align its 2021 to 2025 investment plan with customer expectations.

Phase II of the engagement focused on two core objectives:

1. Confirming customers' needs, preferences and priorities identified in Phase I; and,
2. Soliciting customer feedback on the content of NPEI's draft plan, including customer preferences towards particular capital investments where trade-offs on pacing exist.

The seven specific investments were presented in the form of trade-off questions. In most cases, these investments were presented as a choice between several approaches – the pace of investment included in NPEI's draft plan; an *accelerated pace*; or a *reduced pace*. The individual bill impact (customized by rate class) of each approach was presented alongside the choice.

Beyond presenting bill impacts for individual approaches to pacing investments, the workbook – which can be found in its entirety in **Appendix 7.0** – allowed customers to review the cumulative impact of their choices and adjust their responses using a dynamic "bill calculator". Customers were able to change their responses until they felt they had found the right pace of investments and estimated rate impact.

The following section summarizes customer feedback from the online workbook which was sent to all residential, small business and GS >50 kW customers with an email on file.

Phase II: Key Findings

Overall, a strong majority of NPEI customers, in each rate class, support either what is currently included in the utility's draft plan, or an approach that accelerates the pace of investment.

In fact, when it comes to *underground cable replacement, overhead pole replacement*, and *overhead transformer replacement*, many customers from each rate class, support an accelerated investment approach. These three investments consistently received the strongest levels of support.

The results below demonstrate that regarding *underground cable replacement, overhead pole replacement*, and *overhead transformer replacement,* most customers support an approach that falls somewhere between what is included in the draft plan and a more accelerated pace of investment.

Underground Cable Replacement

Relative to other investment options presented to customers, underground cable replacements received some of the highest levels of support for an accelerated approach. Almost equal proportions of residential and small business customers support an accelerated approach, while GS >50 kW customers are more divided between what is currently included in the draft plan and a more proactive investment approach.

Underground Cable Replacement *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Further Accelerated Pace	29%	31%	2/32	25%
Accelerated Pace	36%	37%	14/32	36%
Included in Draft Plan	35%	32%	16/32	38%

Despite a correlation between whether your electricity bill has a significant impact on household finances and the likelihood of supporting a move accelerated approach to underground cable replacement, a majority of all respondents either support the approach in the draft plan or an accelerated pace. In fact, a majority of residential customers who say their bill has a *significant* impact on their households' finances support either the current or an accelerated approach.

Underground Cable Replacement *Residential Customers*	**Bill Impact on Finances**		
	Significant Impact	Impact	No Impact
Accelerated Pace	27%	24%	34%
Included in Draft Plan	31%	39%	37%
Slower Pace	43%	37%	29%

Overhead Pole Replacement

Overhead Pole Replacement *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	47%	56%	10/32	45%
Included in Draft Plan	35%	31%	15/32	33%
Slower Pace	18%	13%	7/32	22%

Overhead Transformer Replacement

Overhead Transformer Replacement *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	47%	53%	14/32	45%
Included in Draft Plan	36%	28%	12/32	33%
Slower Pace	17%	19%	6/32	23%

Grid Modernization

With regards to investments in Supervisory Control and Data Acquisition (SCADA) systems, NPEI customers are almost evenly divided. Nearly equal proportions of residential, small business and GS >50 kW customers support either the approach included in the draft plan, or an accelerated one that would see the number of devices installed doubled over the next five-year period.

Grid Modernization *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	41%	41%	12/32	33%
Included in Draft Plan	44%	41%	14/32	46%
Slower Pace	14%	18%	6/32	20%

Despite strong overall support for an accelerated approach to installing SCADA systems, there is a high degree of correlation between bill impact on finances and one's likelihood to support higher levels of spending. In fact, more "vulnerable" residential customers are more likely to support a slower pace than an accelerated pace of investment.

Grid Modernization *Residential Customers*	Bill Impact on Finances		
	Significant Impact	Impact	No Impact
Accelerated Pace	26%	38%	50%
Included in Draft Plan	38%	47%	44%
Slower Pace	36%	15%	6%

The investments which received the lowest levels of support relative to the other options presented included: *Converting outdated underground kiosk transformers*, *subdivision underground rehabilitation*, and *overhead rebuilds*.

Converting Outdated Underground Kiosk Transformers

Converting underground kiosk transformers was the one investment option that was presented without an accelerated approach. The pace included in the draft plan, which was in line with historic rates of replacement, was supported by the majority of customers in each rate class.

That said, nearly 4-in-10 residential and small business customers expressed their support for an investment pace below what is included in the draft plan. This propensity to support a slower investment pace was the lowest amongst the seven investment options presented to customers.

Kiosk Transformers *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Included in Draft Plan	56%	60%	21/32	45%
Reduced Pace	30%	23%	4/32	39%
Slower Pace	14%	17%	7/32	17%

When it comes to replacing kiosk transformers, customers who's bill significantly impacts their finances hold much different views than other customers. In fact, a strong majority of these customers say that NPEI should take a slower approach to replacing this equipment compared to what it currently being proposed.

Kiosk Transformers *Residential Customers*	**Bill Impact on Finances**		
	Significant Impact	Impact	No Impact
Included in Draft Plan	27%	53%	69%
Reduced Pace	37%	33%	25%
Slower Pace	36%	14%	6%

Relative to the other investments presented to customers, *subdivision underground rehabilitation*, and *overhead rebuilds* saw the weakest support for an accelerated investment approach. About 3-in-10 residential and small business customers supported an accelerated pace, while a plurality would prefer what is currently included in the draft plan.

Subdivision Underground Rehabilitation

In fact, a plurality (14 of 32) GS >50 kW customers supported a slower pace of subdivision underground rehabilitation, provided that they would not be directly impacted by such investments.

Subdivision Underground Rehabilitation *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	33%	34%	6/32	31%
Included in Draft Plan	45%	52%	12/32	45%
Slower Pace	22%	14%	14/32	24%

Overhead Rebuilds

Similarly, almost equal proportions of customers in all rate classes offer the same levels of support for *overhead rebuilds*.

Overhead Rebuilds *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	32%	35%	5/32	26%
Included in Draft Plan	50%	45%	19/32	52%
Slower Pace	19%	20%	8/32	23%

In its upcoming application, NPEI is considering a rate design change for GS > 50 kW customers. These customers were presented three options and asked to provide feedback – the status quo fixed-variable split, and two options with a higher fixed rate, including what they are proposing in the draft plan.

Potential changes to fixed versus variable distribution rates

In total, 20 of 32 GS > 50 kW customers support the rate design included in the draft plan, with 11 of 32 supporting the status quo. Based on this feedback, there does not appear to be a propensity for customers to support a higher fixed distribution charge than what is currently being proposed.

Online Workbook	GS >50 kW
Status Quo (15% fixed; 85% variable)	11/32
Included in Draft Plan (21% fixed; 79% variable)	20/32
Higher Fixed Distribution Charge (33% fixed; 66% variable)	1/32

Cumulative Bill Impacts

After providing their preferences on the seven investments presented in the workbook, customers had the opportunity to review the cumulative impact of their choices and adjust their responses using a dynamic "bill calculator".

It was made clear to participants that these impacts were *in addition to* what is included in the draft plan, for residential customers, this was a 2.5% increase over 5-years. If customers selected the *"Included in the Draft Plan"* option for each investment, the rate impact was zero. For residential customers, the range of potential impacts was +$0.23 if they selected all of the most accelerated approaches, and -$0.10 is they consistently selected the slowest approaches.

On average, customers did not make significant changes to their initial responses. In fact, for both residential and small business customers, the average rate increase rose by $0.01 after customers had the opportunity to adjust their responses. Customers on average were more likely to select the accelerated pace of investment once given the opportunity to see the cumulative impact of their choices. It should be noted, however, that these changes cannot be deemed statistically significant, essentially meaning that there was no change from initial to final responses.

Cumulative Bill Impacts	Residential	Small Bus.
Average Initial ($)	$0.08	$0.16
Average Final ($)	$0.09	$0.17

Assessing NPEI's Draft 2021-2025 plan

Overall, customers in all rate classes are prepared to pay for the level of investment included in NPEI's draft plan. In fact, customers are between two and three times as likely to support a more accelerated investment approach compared to a slower approach that keeps rates below what it currently proposed.

Again, when it comes to *overhead pole replacement*, *overhead transformer replacement*, and *underground cable replacement,* most customers support an approach that falls somewhere between what is included in the draft plan and a more accelerated pace of investment.

Assessing NPEI's Draft Plan *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Improve service, even if it exceeds proposed increase	33%	26%	4/32	27%
Maintain proposed increase	49%	57%	20/32	45%
Keep increases below proposed	11%	13%	6/32	18%
Other	2%	1%	1/32	2%
Don't know	5%	2%	1/32	9%

Specific attention has been paid to how those whose electricity bill has a significant impact on their households' (or business') finances opinions vary from the broader customer base. Reflecting their financial capacity, those who agree that their electricity bill has a *significant impact* on their household's finances are less supportive of investments than the average customer but still generally support NPEI's draft plan and the associated impacts. Still, it is important to note that about 3-in-10 of these more "vulnerable" customers believe that NPEI should keep increases below what is currently proposed.

Assessing NPEI's Draft Plan *Residential Customers*	**Bill Impact on Finances**		
	Significant impact	Some Impact	No Impact
Improve service	17%	27%	43%
Maintain increase	36%	55%	50%
Keep increases below	29%	13%	3%

Across NPEI's service territory, there is limited regional variance regarding support for the utility's draft plan and associated impacts. As shown below, customers located in Niagara Falls/Pelham are more likely to support a more accelerated approach to investment, even if it could result in higher rate impacts.

Assessing NPEI's Draft Plan *Residential Customers*	Regional Segmentation		
	Niagara Falls/Pelham	Lincoln	West Lincoln
Improve service	43%	38%	38%
Maintain increase	41%	52%	50%
Keep increases below	16%	10%	12%

Phase II: Workbook Diagnostics

A principle element of utility rate applications, as outlined by the OEB, is the ongoing nature of customer engagement. The OEB states: *"Planning is an ongoing utility activity, not just something that is done in preparation for a rate application. Likewise, customer engagement to inform utility planning must also be an ongoing activity."*[2]

Considering the ongoing nature of customer engagement, it is important to understand whether customers had a favourable impression of the utility's efforts to gather feedback on its plans, and if there are areas that could be improved upon for future engagements.

Overall Impression of Workbook and Volume of Information

Overall, the vast majority of customers who completed the online workbook had a favourable impression. When asked whether there was anything that was left unanswered after completing the workbook, almost all customers said there were "none".

Online Workbook *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Favourable	88%	96%	28/32	84%
Unfavourable	7%	1%	3/32	9%

Likewise, an almost equal proportion of customers felt that the online workbook provided *"just the right amount of information"*, with only 9% of low-volume customers saying, *"too little"*.

Online Workbook *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Too little	5%	5%	5/32	10%
Just the right amount	86%	87%	23/32	80%
Too much	9%	9%	4/32	10%

[2] Handbook for Utility Rate Applications, p. 12 (October 13, 2016)

Customer Engagement Approach

As mentioned earlier, NPEI and INNOVATIVE developed and executed a two-phased customer engagement approach. This approach created multiple opportunities for customers to provide feedback, and provided NPEI with multiple opportunities to consider and incorporate customer feedback as part of the planning process.

While detailed methodologies are contained within each individual report as appendices, this section will highlight some of the key methodological elements of NPEI's 2021-2025 customer engagement approach.

Summary of NPEI's Customer Engagement Results – Phase I and Phase II

Customer Group	Methodology	Unweighted Sample Size	Field Dates
Residential	Telephone	n=505	July 9 – 26, 2019
Small Business	Telephone	n=87	July 9 – 26, 2019
Residential	Online	n=939	July 12 – 29, 2019
Small Business	Online	n=71	July 12 – 29, 2019
Phase 1 Total Customers Engaged: n=1,602			
Residential	Online Voluntary	n=224	December 2 – 17, 2019
Small Business	Online Voluntary	n=9	December 2 – 17, 2019
Residential	Online Representative	n=1,264	November 21 – December 17, 2019
Small Business	Online Representative	n=56	November 21 – December 17, 2019
Commercial (GS > 50 kW)	Online Representative	n=32	December 3 – 18, 2019
Phase 2 Total Customers Engaged: n=1,585			
Total Customers Engaged as Part of NPEI's 2019 Customer Engagement: 3,187			

Phase I Approach

In Phase I, Niagara Peninsula Energy and INNOVATIVE set out to understand two core elements about its customers.

First, as discussed in detail throughout this report, a key objective of Phase I was to develop an understanding of NPEI customers' needs and preferences. Feedback from this phase helped NPEI planners and engineers inform the design of the utility's draft investment plan, which was shared in draft, with customers in Phase II.

Second, in order to move to a more online-centric approach to engagement, INNOVATIVE needed to develop a detailed understanding of the differences between customers with known email addresses (email sample) and the broader customer base (telephone sample).

INNOVATIVE was able to confidently ascertain the potential differences between these two sample groups by first fielding two parallel online and telephone surveys (see **Appendix 2.0** for details) and then undertaking a rigorous "sample validation" process.

This sample validation process included comparing known variables (i.e. region and electricity consumption) across the overall population to the sample of that of the population with email addresses. Through this process, INNOVATIVE was able to conclude that no "group" is substantially underrepresented in the email sample.

Email Sample versus Broader Sample

Coverage is lower among residential customers among whom 27% of the full population have email addresses on file, while among GS<50 customers 44% have email addresses on file.

Rate Class	Full Population	Email Coverage	
Residential	48,421 records	13,154 records	**27%**
Small Business	4,496 records	1,928 records	44%

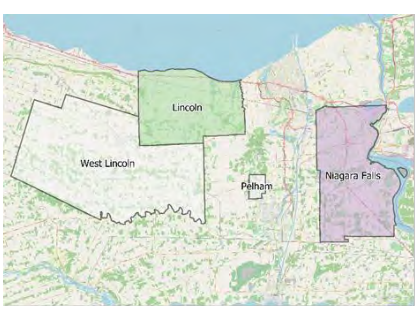
Average consumption is higher for customers in the email sample than it is among the full population for all rate classes. The largest differences exist among both groups of business customers. The final data is weighted on consumption to account for this difference.

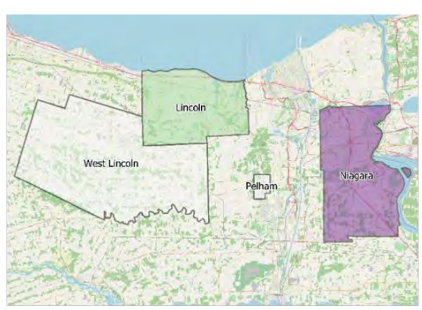
Rate Class	Full Population	Those with email addresses	Difference
Residential	700 kWh	727 kWh	+4%
Small Business	2,154 kWh	2,413 kWh	+12%

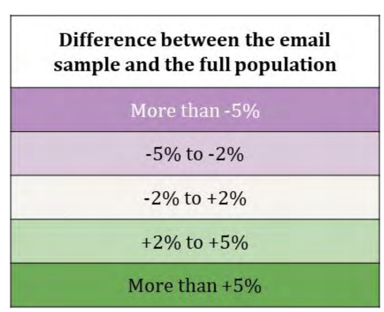
Comparing the overall population to that of those with population with email addresses across known variables, we can see that no group is substantially underrepresented in the email sample. Therefore, no additional weighting "correction" is needed to account for the differences in sample groups.

Regional Segmentation

Customers are grouped into regions based on the service area listed on their account: Niagara Falls, Lincoln, West Lincoln, and Pelham.







Residential **GS<50**

Among residential customers, Niagara Falls as a region makes up 70% of the full population, but only 66% of the email sample. Lincoln makes up only 18% of the full population, but 21% of the email sample.

Among small business customers, the difference between the full population and the email sample is slightly larger for Niagara Falls and Lincoln. Niagara Falls is 65% of the full population and only 60% of the email sample, while Lincoln is 20% of the full population and 23% of the email sample.

The sample is stratified by region to ensure that the final email results reflect the actual regional composition of the population.

Based on the comparative results of the first phase of the customer engagement, INNOVATIVE is confident that the residential and small business online workbooks from Phase II are representative of NPEI's actual customer base.

Phase II Approach

In the **second phase**, NPEI and INNOVATIVE collectively developed an online "workbook" which was subsequently sent to all customers with an email address on record.

The residential and small business online workbooks featured two input streams:

1. The **representative stream** ensures a representative sample of customers are engaged, allowing for the generalizability of findings. This is a report of those responses.
2. The **voluntary stream** created an open process that allowed anyone who wants to be heard an opportunity to express themselves, including those who have not provided the utility with an email address.

The GS>50kW workbook was only accessible through a unique URL sent to customers. There was no voluntary stream for this version of the workbook.

In the **representative stream**, each customer received a unique URL that could be linked back to their annual consumption, region and rate class. In total, the workbook was sent to 13,855 customers through an e-blast from INNOVATIVE.

- 11,962 residential customers;
- 1,446 small business customers, and
- 447 GS > 50 kW customers

Beyond the initial e-blast, customers in all rate classes were sent multiple reminder emails to encourage participation. Additionally, to encourage participation amongst GS > 50 kW customers, NPEI staff placed follow-up telephone calls.

For residential and small business rate classes, responses from the representative stream were weighted by region and usage to ensure the responses were representative of the broader customer base. Due to sample size amongst GS > 50 kW customers, a decision was made to not weight data and present results in terms of n-size rather than percentages.

The **voluntary workbook** was promoted through NPEI's website, and social media.

Because INNOVATIVE cannot definitively link those who completed the online workbook through the voluntary stream, this portion of the sample cannot be deemed representative of the broader NPEI customer base.

While not representative of the broader customer base, the voluntary workbook is intended to ensure that customers who have not provided NPEI with an email address have an opportunity to participate.

An initial overview of the residential and small business workbook, based on 1,154 completed workbooks was shared with NPEI on December 12, 2019.

- The draft representative workbook results were shared on January 15, 2020.
- The draft voluntary workbook results were shared on January 15, 2020.

Throughout both Phase I and Phase II, INNOVATIVE regularly provided NPEI staff with progress updates by way of telephone, including preliminary results.

Appendix 1.0

INNOVATIVE
RESEARCH GROUP

CUSTOMER ENGAGEMENT

Exploratory Low-Volume Customer Focus Group Report

July 2019

Prepared for:
Niagara Peninsula Energy Inc.
7447 Pin Oak Drive
Niagara Falls, ON L2E 6S9

npe niagara peninsula energy inc.
Your Local Utility

Customer Engagement:

Exploratory Low-Volume Customer Focus Group Report

July 2019

Confidentiality

This Report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Niagara Peninsula Energy Inc.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Niagara Peninsula Energy Inc. (NPEI). The conclusions drawn and opinions expressed are those of the authors.

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1. Executive Summary

In general, focus group participants were aware of the role Niagara Peninsula Energy Inc. (NPEI) plays in terms of their direct relationship as a customer (e.g. billing and maintaining reliability). Very few participants knew of NPEI's role in the larger electricity system in Ontario, including their limited decision-making power in regards to sourcing electricity and determining the price customers pay.

Participants were extremely satisfied with the customer service provided by NPEI. Generally, focus groups participants were also satisfied with their level of reliability; some participants noted that they had never experienced a single outage with NPEI. The biggest pain points for most participants was the price of delivery and lack of information that connects their electricity usage to the final amount charged on their bill.

Five key topics were discussed as emerging issues that will affect NPEI's ability to deliver electricity in the coming years. These included preparing the system for climate change, greening the grid and microgeneration, accommodating the increasing adoption of electric vehicles and devices, system maintenance, and a need for education among customers and the local community.

Following the discussion about emerging issues, participants were asked to rank the top three priorities that they want NPEI to focus on in their upcoming plan. The table below outlines the results of this exercise, which are discussed in greater detail on page 12. Price and cost efficiency were most often listed as the first priority, twice more than any other priority discussed.

Priorities	1st Priority	2nd Priority	3rd Priority	Total
Price/Cost Efficiency	15	7	8	30
System Maintenance/Reliability	3	8	3	14
Greening the Grid/Microgeneration	3	5	6	14
Need for Education	2	2	6	10
Customer Service/Tools	2	3	3	8
Supporting Local Community/Small Business	2	4	2	8
Planning for Growth/Increased Demand	2	1	3	6
Preparing System for Climate Change	2	0	0	2

2. Low-Volume Customer Focus Groups

2.1 Methodology

Objective: Using an exploratory research methodology, our objective was first to understand the customer journey, from initial contact (typically account initiation or transfer) through to the various other touchpoints customers typically encounter.

Our second objective was to obtain insights into what customers expect of Niagara Peninsula Energy Inc. (NPEI) particularly in terms of what represents value to customers and what customer priorities for NPEI are, both in context of valued outcomes and choices impacting customers.

Four low-volume customer focus groups were conducted in total across June 25th and 26th, 2019.

June 25th in Niagara Falls

1. Small Business Customers (9 participants) – 5:30pm to 7:30pm
2. Residential Customers (9 participants) – 8:00pm to 10:00pm

June 26th in West Lincoln

3. Small Business Customers (7 participants) – 5:30pm to 7:30pm
4. Residential Customers (8 participants) – 8:00pm to 10:00pm

Small Business participants received a $125 cash incentive as compensation for their time, while residential customers received $100. Participants were recruited from across Niagara Falls (June 25th) and Lincoln (June 26th) and qualified if they either paid their organization's electricity bill or had oversight on electricity management decisions.

We used a detailed *Discussion Guide* to moderate both focus groups. In both focus groups, a printed primer was shared with participants in the early part of the session to provide consistent contextual information on Niagara Peninsula Energy and the role it plays within Ontario's electricity system, and bill impact.

This report summarizes key findings, and offers observations and potential strategic avenues based on these groups and past research. *Respondent verbatim responses are in italics.* Regional differences or differences between residential and small business customers will be noted in the report where and if they exist. In general, our approach in reporting is to allow the respondents to be heard as much as possible, utilizing representative verbatim comments, offering interpretation and comment where necessary.

Please Note: Qualitative research does not hold the statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used for strategic direction only.

A note on interpreting focus groups findings: In focus group research, the value of the findings lies in the *depth* and *range* of information provided by the participants, rather than in the *number* of individuals holding each view. References in this report such as "most" or "some" participants cannot be projected to the full population. Only a large sample, quantitative survey would be accurately projectable to the full population.

2.2 Customer Knowledge

Focus group participants varied widely in their knowledge about the role of NPEI in Ontario's electricity system. In each group, there was at least one customer who was able to explain NPEI's role with some detail.

> *"Admin. [NPEI] does all of our billing, sends out crews, [delivers electricity to] new subdivisions, and they do what you're doing, which is anticipating the future."*
>
> *"They make sure the lines are all up to date. [They manage] all the infrastructure in the Niagara Falls region."*

In most cases, participants were able to explain what NPEI does within the context of their experience as customers. This included mentions of billing, reliability, previous experience with conservation programs, and customer service.

> *"They have excellent twitter service. I can go online and or go on twitter and see exactly when my power if going to come up."*
>
> *"Take care of billing."*
>
> *"I think they have some education programs, do they not? For the public to stay away from power lines and what not? To teach children."*
>
> *"Conservation programs."*
>
> *"New services. Programs for getting fluorescent lighting."*

In most groups, general dissatisfaction with pricing came up in discussion early on. Often, this was expressed as a perceived unfairness about the cost of the delivery charge. Despite this, participants who had contacted NPEI to discuss their dissatisfaction with their bill were very satisfied with the level of customer service they received over the phone.

> *"Take our money"*
>
> *"We have a natural energy source in our backyard and yet my delivery charge is $40 a month."*
>
> *"I understood why [my bill] went up [when I called]. She was really good at looking into it and making a payment plan for me."*

After participants had an opportunity to share their knowledge about NPEI's role in the electricity system, they were given a one-page (double-sided) primer on the electricity system in Ontario and NPEI's role within it. The residential version of this handout is in the appendix of this report, for reference.

Participants were asked if anything in the handout was surprising or new information. Across all groups, participants stated previous unawareness to how the cost of their electricity service was divided. The majority of those who stated this was new information said they believed that the entirety of their bill went to NPEI.

> *"I thought they got at least a third of the bill."*
>
> *"I guess it's just a little bit of ignorance in not knowing how it was split up."*
>
> *"I had no idea they split it."*

Other surprising information included the degree to which NPEI controls aspects of participants' electricity service. Decisions surrounding generation and pricing were most commonly cited as things that participants initially thought NPEI had more control over. Some participants perceived inefficiencies that arise from having too many stakeholders in Ontario's electricity sector.

> *"I don't know if I was surprised, I kind of thought that they bought and distributed the power."*
>
> *"It's kind of confusing where all our money is going."*
>
> *"This was very educational for me. I didn't know who made these kind of decisions."*
>
> *"A lot of the issues we have are out of NPEI's control."*
>
> *"I didn't know that the cities themselves were stakeholders in this."*
>
> *"We could be a country that is totally self-sufficient, but we are not. We may take way too much time and research because there are so many hands in the pot. We have four levels of government and by the time that all these parties come together it's going to go beyond the scope of what was originally planned. What's going to happen when we putting everything off so far and then we will have nothing left?"*

Although most participants agreed that they were previously unaware as to how the bill was split among stakeholders, there was still some discussion as to whether or not the portion of delivery was too high or low.

> *"24% for delivery sounds high to me…3% line loss is too much"*
>
> *"To me, that seems low."*
>
> *"Seeing what the bottom line of their financial statements would be a different story. Sure they are taking 24% of all the bills, but how much is that?"*

After reviewing the handout, some respondents wanted more information about how decisions are made in Ontario's electricity system and NPEI's role within that process. Some participants wanted to know how comparable their service with NPEI is to other local distribution companies.

> *"Is it the energy board that makes sure that the utility is following the laws and policies that are in effect?"*
>
> *"One of the things that is missing here on this circle is the debt repayment charge."*
>
> *"Is there a legislature that municipalities have to own the utility?"*
>
> *"Do you have anything to compare NPEI's service to other utilities that serve similar customers?"*

A couple participants in the small business group in Lincoln said they had difficulty trusting the numbers presented on the handout and whether NPEI will really make changes based on customer feedback.

> *"I don't know if I trust these numbers."*
>
> *"We can hope, [but] whether they listen is the issue."*

2.3 Customer Journey

Customer experience varied more across region than customer type. In general, customers in the Niagara Falls group expressed satisfaction with interactions with NPEI more frequently and with more enthusiasm than those in the Lincoln groups.

Among participants who had previous experience with another utility (e.g. Toronto Hydro), comparisons between interactions and reliability were expressed and discussed. NPEI was nearly always perceived to have better customer service reliability than other utilities, more so among those with previous experience with Toronto Hydro than utilities in Hamilton and surrounding areas.

2.3.1 Points of Contact

Contact with NPEI varies across residential and small business customers. For most residential participants, most contact with NPEI occurs over the phone.

> *"I have phoned them a couple times. First time it was to get connected…It was a frustrating process to tell them that I didn't need to go through a lawyer to get connected. The other time was to tell them I was turning 65 and I needed a lower rate."*

> *"I called them to discuss a $900 bill. I live in a small house, no dishwasher, no furnace, no washer/dryer. The girl on the phone was really nice and calming, but I said the energy company should have a service where they can send somebody to your house. They said no and that they didn't have anything they could do for me."*

> *"I have called them to complain about the rebate."*

For small business customers across Niagara Falls and Lincoln, points of contact were more varied, with many Niagara Falls participants citing in-person experience with the LED lighting conservation programs.

> *"They called me to redo all my lighting to LED a while ago, for free. That was nice and quick and efficient."*

> *"I think they phoned first and then they came out. And then I wanted more and then I had to pay. But I got the fifteen hundred dollars' worth."*

Other points of contact for small business customers included visiting the head office to set up an account, going online, or calling customer service.

> *"When I have to go into the head office to get [a new account]."*

> *"Online, that's it. They are literally next door to us in their building. But online it's so easy and they are so nice if you have to call. Sometimes they ask me to go paperless, but I need the paper for my accounts payable."*

> *"Whenever there is an issue, we call them. Customer service has always been nice as opposed to talking to customer service from Bell Canada…"*

In Lincoln, one small business customer noted disappointment in the lack of communication from NPEI to small business customers. Citing previous conservation programs, small business customers in Lincoln noted a desire for more services that would help decrease energy use.

> *"I just feel like I'm not cared about. Call me and tell me what you can offer. I'm not in this industry, I am not a power guy. Help me, come in here and tell me what to do. Let me see them as somebody trying to help me."*

> *"An energy conservation audit [would be helpful], where they come in and see how much electricity is being used and where. I think some utilities still offer that service, but I don't know if they target it to larger commercial users."*

Across all groups, customers were very satisfied with the level of customer service they received from NPEI. While one customer expressed dissatisfaction with the automated telephone menu, customers who connected with a customer service representative had mostly, if not exclusively, positive things to say.

> *"I had to press 2 like 5 times before I actually got a person."*

> *"Turnaround time was extremely quick, everything we had done was really, really timely. Everything was done in about 6 hours, I would say."*

> *"We wanted to put decorative lights on our poles in the Fallsview area so we had some meetings with Hydro to figure out what we could put up there, they had to figure out what the actual cost was going to be so they could meter them. That was quite an easy process with them."*

> *"They kept in touch with me until the project was done. I felt like I won the lottery."*

> *"I have been here just under a year and I've never had to contact Niagara Peninsula Energy. I haven't ever had an outage."*

2.3.2 Customer Expectations: Price and Reliability

When the conversation was directed towards customers' expectations of NPEI rather than their experiences, participants in Niagara Falls were quick to express concerns over price.

> *"We try to deprive ourselves [of using electricity] but our bill doesn't change much."*

> *"You save but your bill never goes down."*

Some participants shared an expectation that prices in Niagara Falls should be lower because of the power generation provided by the Falls.

> *"We live in the city where it's produced. When they brought in the casinos they said that it would reduce what we pay and it hasn't."*

> *"We have a natural energy source in our backyard and yet my delivery charge is $40 a month."*

However, even among those that are frustrated with the cost of electricity, participants express appreciation for the customer service that NPEI provides.

> *"It often seems that they put in methods for you to save money and then they raise the rates. It's like you never really catch up on it. It feels like the onus is on the user to spend less money but they you never really bring the bill down. I have not had bad customer service ever, not even residentially. It is what it is. You're going to need electricity."*

Participants in the Niagara Falls residential group noted a distrust in how their bill amounts are calculated. They wanted an avenue to better monitor their energy use so that they can see the relationship between their usage and their bills. Most participants in this group were unfamiliar with the current service offering of NPEI through the online 'My Account' functions. This offering was something that participants said they would value and would be willing to pay more for.

> *"How do we know that the amount their charging us is the right amount? I don't see numbers."*

> *"That would be awesome to have. Data on how much energy we are using by the minute."*

> *"It would be great if a smaller company like Niagara Peninsula to be an innovator to have an app on your phone that you could check to see your usage."*

> *"Even if it's $5 more on your bill, most people won't even notice that. Some people might, but I think that I would be open to exploring that."*

In Lincoln, expectations of participants were more centred on reliability. Participants in the small business group mentioned improvements in the reliability of their service over the past years.

> *"When I have no power, I can't operate my business. But in the three years that I have had [my business] that has never been the case."*

> *"They used to have a lot of outages and it would be hours and hours and hours. It's better now."*

For many participants and across all groups, their relationship with NPEI is seen as little more than a bill to pay. Electricity is recognised as a necessary service and one with little-to-no choice involved throughout the customer journey.

> *"Expensive, but necessary. Not much you can do it. Excellent customer service. Both business and [residential]"*

> *"Essential, can't do anything about it."*

> *"I pay my bill that's it. I pay, I don't have another option. I pay my bill and that's the end of it."*

2.4 Emerging Issues

Frequently identified issues and associated priorities were consistent across all groups, and can be described as:

- **Preparing the System for Climate Change**
- **Greening the Grid and Microgeneration**
- **Changing Consumer Behaviour: Electric Vehicles and Devices**
- **System Maintenance**
- **Need for Education**

2.4.1 Preparing the System for Climate Change

Respondents understand the connection between reliability and weather through first-hand experience. Participants in Lincoln were especially understanding about the challenges of maintaining reliability though changing weather and during colder months.

Across all groups, participants were concerned that as weather continues to get more severe, the effects on reliability and the system in general will be a challenge.

> *"Weather is going to be more erratic. They have built the system to follow certain patterns, but we are going to start seeing more erratic patterns of weather. We are getting more peaks and valleys, especially in winter, which can cause a lot of issues with infrastructure."*

> *"How are they going to handle those big waves? Downed power lines, the trees?"*

Most participants agreed that addressing climate change should be an issue addressed proactively, rather than reactively.

> *"Don't wait for something catastrophic to happen to throw resources at it."*

There was a minority of participants who disagreed about whether climate change is a serious concern or not.

> *"I don't buy into this environment stuff. I don't drink the Kool-Aid. I think it's a way for government to have control."*

2.4.2 Greening the Grid and Microgeneration

Beyond preparing the system for more severe weather, participants noted a desire for NPEI to be a leader in green initiatives and reducing the impact of energy generation and consumption on the environment. Even without having much knowledge about specifics, participants were quick to name the environment as an important stakeholder in NPEI's decision-making.

> *"Sustainability. I think of it as renewable energy. Like lowering our impact when it comes to emissions."*

> *"What about their equipment? Is it needed to be replaced with electric vehicles? Is there office green? Are their vehicles green? Are they showing an example?"*

> *"Is burying the lines good for the environment? Or is it better for the environment if the lines are up in the air? Is it just better for us or better for the environment?"*

> *"Environment. I am just throwing that word out there, I don't know what it means, but I know that they should be environmentally responsible."*

Power storage and microgeneration through solar panels were most often mentioned by participants as ways to lessen the environmental impact of the grid. Cogeneration was also mentioned as a technology to support and encourage.

> *"There will be an increase in need for power. Oh the system we have enough now? And we are giving that away to the US? That's fine for now, but don't count on that to last. They need to seek out situations where we can make our own power."*

> *"Can they look at buying back power from their customers, do they have any control over that? Is that something they could look into?"*

> *"Technology and developing new sources of generations. Cogeneration technology like greenhouses and number of businesses that use a lot of heat can find efficiencies by working together through microgeneration."*

These were seen as attainable technologies to invest in given their broader adoption in Europe and potential economies of scale that could be captured through partnership with local developers.

> *"Why does it seem like Canada and the US is so far behind Europe in terms of putting solar panels on peoples' houses?"*

> *"The costs [to set up a solar panel] are probably half of what they were 5 to 6 years ago. If you put that in to a new subdivision, I bet you could get it down to $3,000 per house."*

2.4.3 **Changing Consumer Behaviour: Electric Vehicles and Devices**

Beyond making changes to the system, participating customers also noted the importance to prepare for changes in consumer behavior – including the increasing adoption of electric cars and the increasing reliance on technology that relies on electricity to run.

> *"Smart cars are getting even more popular. Electric vehicles, they are definitely collecting more than the house and small business hydro now."*

> *"What about appliances that draw so much power?"*

> *"Now, we are using more things, more devices. More devices that use energy even when it's turned off."*

The potential issue of an increased reliance on electric-powered vehicles and devices is increased demand. Beyond this, participants also noted potential challenges of delivering power to charging stations that will need to accommodate the shorter range of electric vehicles in rural areas.

> *"Everybody is pushing electric cars. Some countries are mandating electric cars. If that happens, will our system be able to handle that? And what about in rural areas? Sure, you can drive for 100km, but if there is no station for 200km what are you going to do?"*

2.4.4 **System Maintenance**

Similar to the proactive approach to addressing climate change, participants want NPEI to take a proactive approach to managing infrastructure to maintain reliability. Despite there being very few participants who mentioned experiencing outages, many participants understood that it will cost to maintain their current level of reliability.

> *"Maintaining reliability of the distribution network."*

> *"Just ageing infrastructure."*

> *"I am not mad about the little bit of profit, because it allows them to be able to [deal with] the ageing infrastructure."*

> *"If you don't replace this stuff it's not going to be reliable."*

Participating customers wanted to know that there is a plan to replace infrastructure proactively.

> *"Is there a plan to replace infrastructure for the next 20 years?"*

2.4.5 Need for Education

Participants wanted NPEI to play a larger role in educating their customer base and community members. Once participants learned of the many other organizations represented on their electricity bill besides NPEI, they wanted to see NPEI as a community player and a voice for the customer during interactions with other electricity organizations.

> *"Of the three levels, the local level seems to be the most trustworthy. From that standpoint I would trust [NPEI] a lot more than [generation or transmission]."*

> *"Shouldn't there be more involvement in the community? Why do we not have more involvement in what's going on beyond a focus group? Where we go to City Hall and … I just don't think we have enough say in what goes on. Not just with Niagara hydro but with everybody."*

> *"The people in my building don't get a hydro bill and they don't get that information. So how do we get that information to all the people? About how much it costs to run businesses' electricity? I think that education is not just for the [customer] but for all the consumers using the utility. How can [NPEI] keep those people educated?"*

Participants expressed a desired to want to be more involved in the decision-making process of NPEI, but admitted that they aren't equipped with the knowledge or expertise to really get involved.

> *"If they have an annual report that we have access to. But can we understand it? Is it in laymen's terms?"*

> *"There's not an understanding of how much is involved in the coordination of burying lines. You have to tear up the road and the sidewalks. We don't have the knowledge on how to accomplish what we say we want to accomplish."*

> *"I don't think they are educating people about conservation in a basic way like they used to. They should talk to people about phantom power."*

On more than one occasion, town hall meetings were suggested by participants as a way to get involved in the community and educate customers on how the electricity system works.

> *"What about a town hall meeting. Help people to understand how the grid works."*

Participants across multiple groups said that greater transparency about how prices are made should be an important priority. Other participants said that they would be willing to pay more to learn more about how they are using their energy and how they might be able to reduce their consumption and therefore, their bill.

"They are a business and they have to operate to make money. That is what they are here for. There is nothing wrong with that. But they need to educate people as to why they are charging what they are paying."

"I would be willing to pay $50 bucks to have a guy come write up a two-page report about where I am at."

2.4.6 Other Emerging Issues

Some participants outlined other issues that, while not a main concern of most participants, may be underrepresented in the groups relative to the entire customer base.

These concerns included increased demand due to an increase in big business. With an increase in big businesses, some participants wanted to see NPEI play a role in protecting small businesses through targeted programs.

"Niagara is now getting some big businesses – it's growing."

"I would be willing to pay a little bit more to keep businesses operational. And I am not talking about multi-million dollar businesses but [small, local businesses]"

"Our tourism is what generates most of the income in Niagara Falls. That'll keep growing and there will be more hotels and more attractions and I think that will grow more then they expect."

"This area is going to boom in the next 10 years. As soon as the Go train starts operating back and forth from here to Toronto."

In addition to small businesses, participants noted that NPEI should make an effort to ensure that electricity remains affordable for low-income households.

"Electricity is a necessity, not a luxury. People need to be able to afford it."

"A lot of seniors are living on pension, and their bills are getting higher. Their houses could be paid off but now gas, water, hydro is as much as a mortgage payment."

Safety was also mentioned as an issue, and involved protecting employees and ensuring that the technologies employed are safe.

"Safety for their workers, they have to climb and it's always in the worst weather. What about their safety? It's a dangerous job."

"The effect of hydroelectric waves on our bodies. We have a very high cancer rate here and we have a lot of electricity here. And I think a lot more is known about it than is talked about. Even on how the electromagnetic fields with Wi-Fi affect us. It's a very hush hush thing, it's not an everyday conversation people have. Is there a way to make it safer? Does burying make is safer? Or does it make it worse?"

Some participants also mentioned a desire for NPEI to investigate potential opportunities for income that do not come directly from the ratepayer.

"Alternative sources of income that they can generate for ratepayers. Use the poles to create a mesh network for internet."

2.5 Identified Priorities

Participants were given the opportunity to rank the outcome priorities they identified. In the table below, we have outlined the number of respondents that listed each priority as either first, second, or third, from written feedback collected during the focus groups.

As an example, 15 participants listed price/cost efficiency as their first priority, while 7 and 8 participants listed it as their second and third priorities, respectively.

Priorities	1st Priority	2nd Priority	3rd Priority	Total
Price/Cost Efficiency	15	7	8	30
System Maintenance/Reliability	3	8	3	14
Greening the Grid/Microgeneration	3	5	6	14
Need for Education	2	2	6	10
Customer Service/Tools	2	3	3	8
Supporting Local Community/Small Business	2	4	2	8
Planning for Growth/Increased Demand	2	1	3	6
Preparing System for Climate Change	2	0	0	2

2.5.1 Emerging Issues as Priorities

When asked to give their top three priorities for NPEI based on the emerging issues discussed, the priority of issues did not reflect the amount of discussion around each topic. While participants tended to take a wide perspective when considering emerging issues, the responses for identified priorities seemed to be more personal and directly related to what participants expect from their direct relationship with NPEI. For instance, price, customer service, and supporting the local community were introduced as priorities. The discussed emerging issues appear in the following rank order:

- System Maintenance
- Greening the Grid and Microgeneration
- Need for Education
- Preparing the System for Climate Change

While 'Changing Consumer Behaviour: Electric Vehicles and Devices' does not appear on the list, it is represented in a broader category of preparing the system for growth and increased demand.

2.5.2 Price/Cost Efficiency

While price didn't come up as an emerging issue for NPEI, it is certainly the top priority participants want NPEI to focus on. Concerns over price were often brought up with concerns that they don't know enough about how their costs are calculated. Participants want to be able to trust that the amount on their bill is reflective of efficient management and based on their actual usage.

> *"I trust them but I don't think they are honest. They are taking advantage of us, we are desensitized to prices going up. They are definitely making more money than they are charging us."*

> *"Demonstrating efficiency to me and education the consumer on what they are doing. I want to trust that what I am paying for is the least amount that I have to pay."*

In the Lincoln small business group, there were few participants who expressed an interest in NPEI helping low-income households by being less strict on collections.

> *"It would be great if they could build up a greater reserve so that they could loosen up on collections."*

2.5.3 Customer Service/Tools

Across multiple groups, customers noted the importance of customer service and the tools that make interacting with NPEI easier. Customers' current experiences with customer service were noted to be excellent, but there was fear that changes in the future might affect the level of service they receive.

> *"Doug Ford is proposing to combine our cities. I am concerned that with us merging with St. Catherine's, we are going to not get the same customer service with Alectra that I am used to [with NPEI]."*

Customers also noted that they wanted to be better able to monitor their energy usage through online tools or an app on their phone. Many customers were unaware of the current service offering on NPEI's My Account portal. When asked about the types of communication tools they want NPEI to offer, texting tools were the top mention. Participants want to be able to receive outage updates for their account (or the account of a loved one) on their phone. Further, it was suggested that text updates could be used to monitor and manage usage.

> *"It would be nice to go online and like Cogeco, see what you use today."*

> *"Or like Telus. I want to see what my usage is and then text me if I am going over."*

> *"There are risk factors involved if you are responsible for a parent or child and you need to make sure the power is on."*

> *"Is it not possible to have at a local level to have text messaging to your cell-phones like [Amber Alerts]? That would be a terrific service."*

2.5.4 Supporting Local Community/Small Business

Supporting the local community and small businesses seemed to stem primarily from a discussion in the small business group in Niagara Falls. Following a discussion about the large box-stores that are soon opening in Niagara Falls, participants expressed concern that the smaller businesses won't be able to compete. Participants felt that NPEI could play a role in supporting small businesses through small business incentive programs.

> *"Incentives for small business because as large business comes and people are very excited that Costco is coming there is a price to pay for big box stores, they sell products cheaper, they get other types of incentives. Small businesses are the largest employer in Ontario and there aren't support for them. Those big box stores take a lot of business eat away at the ability with small-businesses to survive. That's part of all of our social responsibility."*

2.6 Turning Priorities into Themes

For the reference surveys, INNOVATIVE developed the priorities mentioned and discussed by NPEI customers in the focus groups into themes for testing in the reference surveys. The table below highlights how initiatives were captured and organized into themes:

Priorities from Focus Groups	Themes for Reference Surveys
• **Price/Cost Efficiency**	• Delivering electricity at reasonable distribution rates • Finding internal efficiencies and ways to find cost savings
• **System Maintenance/Reliability** • **Planning for Growth/Increased Demand**	• Ensuring reliable electrical service • Proactively replacing aging infrastructure that is beyond its useful life
• **Customer Service/Tools** • **Greening the Grid/Microgeneration**	• Providing tools and services that allow customers to better manage their electricity usage • Providing quality customer service and enhanced communications
• **Need for Education** • **Supporting Local Community/Small Business**	• Support the local economy and community groups through new incentives programs
• **Preparing System for Climate Change**	• Upgrading the electrical system to better respond to and withstand the impact of adverse weather

3. Appendices

The following two-page background primer was used in the residential customer focus groups.

Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

1 Generation

Where electricity comes from.

Ontario's electricity is generated by nuclear, natural gas, hydroelectric and renewable technologies such as wind and solar. In Ontario, 70% of electricity is generated by *Ontario Power Generation*, which has generation stations across the province.

2 Transmission

Electricity travels across Ontario.

Once electricity is generated, it must be transported to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, most of which is owned and operated by *Hydro One*.

3 Local Distribution

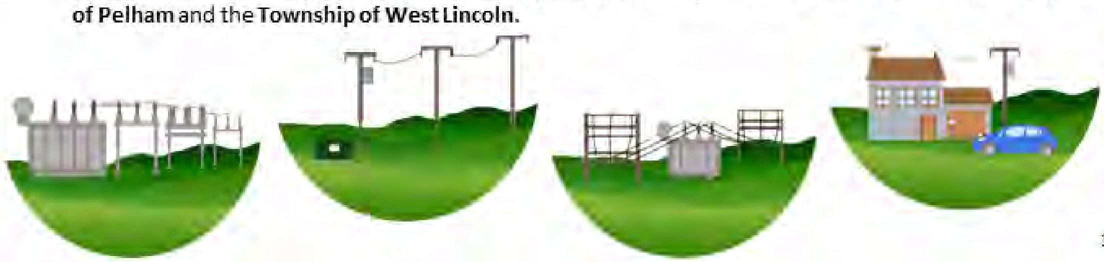
Delivering power to homes and businesses in your community.

npe niagara peninsula energy inc. Your Local Utility

Niagara Peninsula Energy (NPEI) is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, Niagara Peninsula Energy delivers electricity to more than 55,300 homes and businesses.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.



1

Residential Electricity Bills:
Understanding where your money goes

Every item and charge on your bill is either mandated by the provincial government or approved by the Ontario Energy Board (OEB). The OEB sets electricity rates in Ontario.

For the typical residential customer, about **28%** of the electricity bill pays for **NPEI's** distribution system. The rest of the bill goes to power generation companies, transmission companies, regulatory agencies, and government taxes.

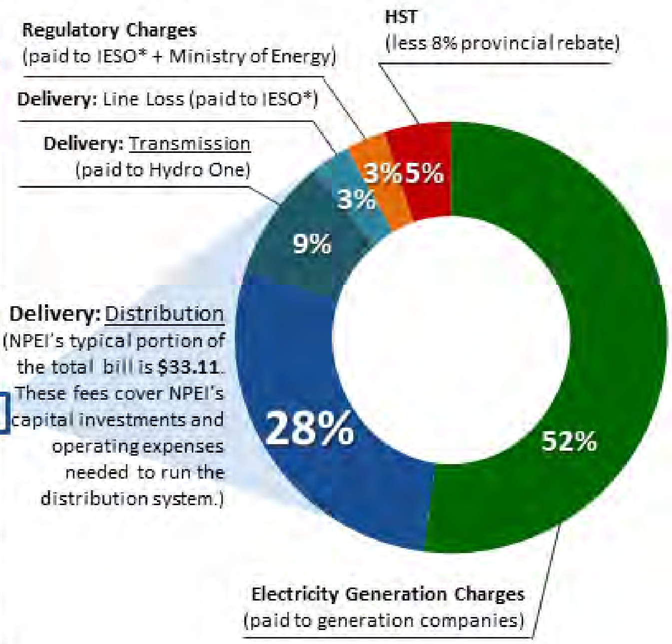
Niagara Peninsula Energy is responsible for billing customers for all of these costs, including any applicable taxes. The "Delivery" charge pays for both the cost of transmission and the cost of distribution. **Only the distribution portion is retained by NPEI to pay for operating and maintaining its part of the system.**

Sample Residential Bill

NPEI Monthly Bill
(Based on consumption of 750 kWh)

NPEI's portion: $33.11

Your Electricity Charges	
Electricity	
Off-Peak @ 6.5 ¢/kWh	31.69
Mid-Peak @ 9.4 ¢/kWh	11.99
On-Peak @ 13.4 ¢/kWh	18.09
Delivery	45.15
Regulatory Charges	3.32
Total Electricity Charges	$116.70
HST	14.46
8% Provincial Rebate*	(-$8.90)
Total Amount	$116.79



* IESO = Independent Electricity System Operator.

How are electricity rates determined in Ontario?

The Ontario electricity sector is regulated by the **Ontario Energy Board** (OEB). One of the OEB's roles is to review the distribution plans of all electricity distributors and set the rates that they can charge customers.

Niagara Peninsula Energy (NPEI) is funded by the distribution rates paid by its customers. Periodically, NPEI is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. NPEI must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity to its customers.

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Reference Survey Report

Customer Engagement

niagara peninsula energy inc.

This report and all of the information and data contained within it may <u>not</u> be released, shared or otherwise disclosed to any other party, without the prior, written consent of Niagara Peninsula Energy Inc.

August 2019

Overview

Research Objective

As part of its Phase I Customer Engagement, Niagara Peninsula Energy Inc. (NPEI) commissioned Innovative Research Group (INNOVATIVE) to survey its residential and small business customers. Among each customer type, INNOVATIVE conducted parallel telephone and online surveys.

Conducting parallel bi-modal surveys serves two primary purposes:

1. **To gather feedback and insights on the *priorities*, *preferences* and *needs* important to low-volume customers**.
   Feedback from these surveys will help NPEI planners and engineers inform the design of the utility's DSP and Business Plan, which will be shared in draft, with customers in Phase II of this engagement.

2. **To establish baselines and develop weights that will allow NPEI to move to an online methodology for future phases of its low-volume customer engagement program**.
   Determining the baseline and understanding the difference between customers with known email addresses (email sample), and the broader customer base (telephone sample), is a critical step for utilities that wish to migrate to representative online survey methodologies in the second phase of their customer engagement. Where significant differences exist between the email sample and the broader customer base (e.g. demographics, firmographics, attitudes, and opinions), the insights gained from these parallel surveys can be used to develop weights, which will account for the differences and ensure generalizable findings.

Benefits of Moving to an Online Methodology

With known emails for approximately 27% of residential customers, and 45% of its small business customers, NPEI could consider migrating from a generalizable pure-telephone methodology to a generalizable pure-online methodology in Phase II of its customer engagement.

The mode of Phase II – the presentation NPEI's draft DSP and Business Plan in interactive workbook form – is well structured to support and demonstrate the benefits of a pure-online methodology. These benefits include:

- Ability to explain concepts using clear, concise, multi-media visuals (e.g. diagrams, pictures, videos).
- Increased potential survey length; it has been documented that respondents are more likely to spend more time participating in online surveys versus telephone surveys.
- Reduced costs as online surveys are less costly than telephone surveys.
- Removing the human element of a telephone survey ensures, that the information NPEI intends to delivery remains invariably consistent.

This report documents the results of four surveys conducted by INNOVATIVE among NPEI's low-volume customers (small business and residential) and provides recommendations on appropriate weighting for future NPEI online survey methodologies.

Comparing known sample variables

Coverage and Consumption Analysis

Comparing the overall population to the sample of that population with email addresses across known variables, we can see that the email sample is largely representative of the overall population of customers.

Overall Coverage

Coverage is lower among residential customers among whom only 27% of the full population have email addresses on file, while among GS<50 customers 44% have email addresses on file. A total of 4710 residential and 88 GS<50 customers did not have either an email address or a telephone number on file.

Rate Class	Full Population	Telephone Coverage	Email Coverage	
Residential	48,421 records	42,958 records	13,154 records	**27% of the full population**
GS<50	4,496 records	4,382 records	1,928 records	**44% of the full population**

Average Consumption

Average consumption is higher for customers in the email sample than it is among the full population for all rate classes. The largest differences exist among both groups of business customers. The final data is weighted on consumption to account for this difference.

Rate Class	Full Population	Telephone Sample	Email Sample	Diff. between email and full
Residential	700 kWh	726 kWh	727 kWh	**+4%**
GS<50	2,154 kWh	2,158 kWh	2,413 kWh	**+12%**

Sector Comparison (GS<50)

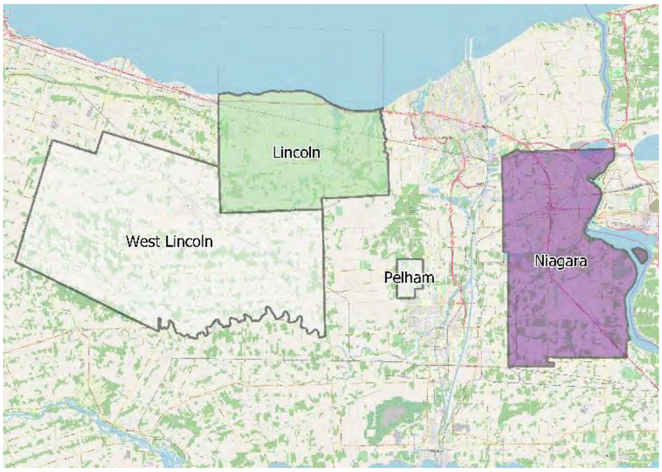
The largest differences in sector of operation come in the GS<50 rate class where Business/Commerce businesses are slightly under-represented and Resource/Construction/Manufacturing businesses are slightly over-represented.

Rate Class	Full Pop.	Telephone Sample	Email Sample	Diff. Between email and full
Business/Commerce	43%	43%	39%	-4%
Public/Cultural	29%	30%	30%	+1%
Resources/Construction/ Manufacturing	26%	26%	30%	+3%

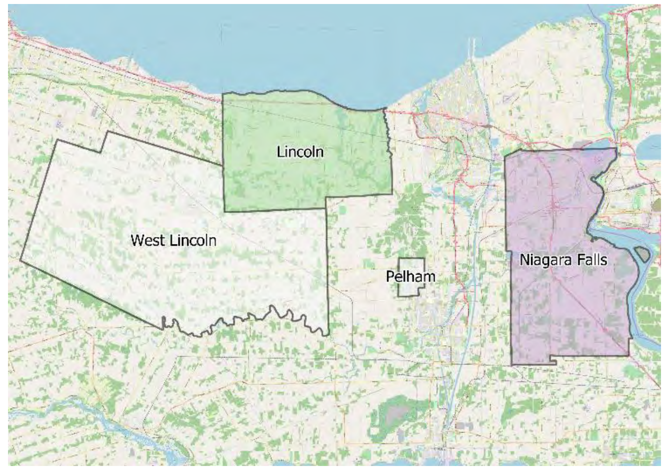
Comparing known sample variables

Regional Analysis

GS<50



Residential



Comparing the overall population to the sample of that population with email addresses across known variables, we can see that no group is substantially underrepresented in the email sample.

Customers are grouped into regions based on the service area listed on their account: Niagara Falls, Lincoln, West Lincoln, and Pelham.

Among residential customers, Niagara Falls as a region makes up 70% of the full population, but only 66% of the email sample. Lincoln makes up only 18% of the full population, but 21% of the email sample.

Among small business customers, the difference between the full population and the email sample is slightly larger for Niagara Falls and Lincoln. Niagara Falls is 65% of the full population and only 60% of the email sample, while Lincoln is 20% of the full population and 23% of the email sample.

The sample is stratified by region to ensure final email results reflect the real regional composition of the population

Difference between the email sample and the full population
More than -5%
-5% to -2%
-2% to +2%
+2% to +5%
More than +5%

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Sample Validation

Email Sample vs. Telephone Sample

For the most part, responses from the telephone and online surveys are very similar within both customers types. However, there are a few distinct difference that are worth noting. The table below documents the differences between the *email* and *telephone* samples.

Residential	GS < 50 kW
Age: Telephone respondents are slightly older than online respondents (age 55+: 67% vs. 62% respectively). **Education:** Telephone respondents are less likely to have continued with education beyond high school than online respondents (69% vs. 80%, respectively). **Household size:** Telephone respondents are more likely to live in single person households than online respondents (26% vs. 14%, respectively).	**Sector:** Telephone respondents are more likely than online respondents to be represented in the commercial sector (33% vs. 24%). **Hours of Operation:** Telephone business respondents are more likely than online respondents to operate during regular business hours (76% vs. 54%).
Familiarity and Satisfaction with NPEI: Telephone respondents are, in general, less familiar (67% vs. 80%) but more satisfied (89% vs. 82%) than online respondents.	**Familiarity and Satisfaction with NPEI:** Telephone respondents are, in general, less familiar (68% vs. 86%) but more satisfied (87% vs. 79%) than online respondents.

Weighting Convention

Given the coverage of email addresses (27% of the customer base among residential and 45% of small business customers) and similarities in known account characteristics (average consumption, language, and region), NPEI's email sample is a good representation of the broader customer base.

While the telephone and online surveys returned similar results, there were some differences on key demographics and firmographics (business characteristics), as well as customer knowledge, attitudes and beliefs that merit a weighting convention, which will be applied in Phase II of the engagement process.

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Key Findings

Phase I Customer Engagement

Based on a review of the OEB handbook and previous rate application decisions, NPEI's customer engagement focuses on two types of questions: ***needs*** and ***preferences*.**

- **Needs questions** focus on understanding the gap between the services and experience customers want and the services and experience customers are receiving.
- **Preference questions** focus on customer views about the outcomes the utility should focus on, priorities among those outcomes, and trade-offs illustrated by choices on specific programs or the pacing and prioritization of investments.

The following key findings are the results of NPEI's random digit dialling telephone survey among residential and small business customers (GS<50kW). Given the similarity between telephone and online results, only the former are reported in the key findings. The full report contains all results.

What are customers' needs?

The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates". Small business customers, however, placed greater emphasis on the lowering or reduction of rates.

	Residential	Small Business
Overall Satisfaction	89% satisfied	82% satisfied
Improving services to customers		
1st	Nothing	*Lower or reduced rates*
2nd	*Lower or reduced rates*	Nothing

Key Findings

Phase I Customer Engagement

What outcomes do customers prioritize?

Customers don't expect NPEI to just focus on one outcome. In fact, the majority of both residential and small business customers feel that the following outcomes are *extremely important*.

- Ensuring reliable electrical service
- Delivering electricity at reasonable distribution rates
- Providing quality customer service and enhanced communications
- Proactively replacing aging infrastructure that is beyond its useful life
- Finding internal efficiencies and ways to find cost savings
- Upgrading the electrical system to better respond to and withstand the impact of adverse weather and climate change

Among competing outcomes, *price*, *reliability*, and *finding internal cost efficiencies* are the top three priorities for both residential and small business customers. When ranked relative to other priorities, NPEI customers see price as the top outcome that the utility should focus on.

Ranking Priorities	Residential	Small Business
Top Priority	Delivering electricity at reasonable distribution rates	Delivering electricity at reasonable distribution rates
2nd Priority	Ensuring reliable electrical service	Ensuring reliable electrical service
3rd Priority	Finding internal efficiencies and ways to find cost savings	Finding internal efficiencies and ways to find cost savings

What reliability outcomes do customers prioritize?

Residential and small business customers have consistent priorities when it comes to reliability. Reducing the *overall number of outages, the overall length of outages,* and improving *restoration time* are the top three priorities for both rate classes.

Ranking Priorities	Residential	Small Business
Top Priority	Reducing the overall number of outages	Reducing the overall number of outages
2nd Priority	Reducing the overall length of outages	Reducing the overall length of outages
3rd Priority	Reducing the length of time to restore power during extreme weather events	Reducing the length of time to restore power during extreme weather events

Key Findings

Phase I Customer Engagement

What investment trade offs do customers value most?

While keeping price at a reasonable and affordable level is an important priority for customers, the majority feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

The majority of residential and small business customers are willing to consider paying more to invest in maintaining reliability, equipping staff with equipment and IT systems, proactively investing in system capacity, and modernizing the grid knowing that it could eventually save money.

Further, the majority of customers support proactive investment in both system capacity and grid modernization. Relative to other trade offs support for investment in system capacity is least intense.

Replacing Aging Infrastructure (System Renewal)

The majority of residential and small business customers are supportive of NPEI making investments in aging infrastructure in order to maintain reliability, even if that results in small rate increases. This option is most strongly supported by small business customers, when compared to other trade offs.

System Renewal (% of customers who selected option)	Residential	Small Business
Invest what it takes to maintain reliability	**62%**	**64%**
Defer investments to lessen bill impacts	**26%**	**19%**

Keeping the Business Running (General Plant)

The majority of residential and small business customers support NPEI making the necessary investments to ensure its staff have the equipment and IT systems that are needed to manage the system efficiently and reliably. This option is most strongly supported by residential customers, when compared to other trade offs.

General Plant (% of customers who selected option)	Residential	Small Business
Make investments necessary	**64%**	**55%**
Find ways to make do with equipment	**23%**	**28%**

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Key Findings

Phase I Customer Engagement

Proactive Investments in System Capacity (System Service)

A slim majority of residential and small business customers are more inclined to say that NPEI should proactively invest in system capacity infrastructure to ensure customers in high growth areas do not experience a decrease in reliability.

Relative to other trade offs, this option has the weakest level of support.

System Service (% of customers who selected option)	Residential	Small Business
Proactively invest in system capacity	**56%**	**52%**
Delay investments in system capacity	**27%**	**28%**

Proactive Investments in Grid Modernization (New Technology)

The majority of residential and small business customers are supportive of NPEI proactively investing in modernizing the grid now, knowing it will cost more now, but could eventually save customers money down the road.

Grid Modernization (% of customers who selected option)	Residential	Small Business
Make proactive investments	**62%**	**55%**
Make investment prioritizing lowest cost	**25%**	**21%**

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Methodology & Respondent Profiles

Reference Survey Methodology

Survey Design

This report documents the results of four surveys conducted by INNOVATIVE among NPEI's low-volume customers (small business and residential).

The **telephone surveys** were fielded from **July 9th to 26th, 2019** amongst a random sample of **n=500** (unweighted n=505) residential and **n=87** (unweighted n=87) small business customers.

Both telephone surveys were weighted by region and consumption quartiles within their respective rate classes to produce a representative sample of NPEI's customer base.

The final sample includes both landline and cell phone respondents, so that individuals who don't have a landline are represented. The margin of error is approximately ±4.5%, 19 times out of 20 for the residential survey and approximately ±10.4%, 19 times out of 20 for the small business survey.

The **online surveys** were fielded from **July 12th to 29th, 2019** amongst **n=939** (unweighted n=939) residential and **n=71** (unweighted n=71) small business customers.

Both online surveys were weighted by region and consumption quartiles within their respective rate classes to report on a representative sample of NPEI 's customer base.

The margin of error is approximately ±3.2%, 19 times out of 20 for the residential survey and approximately ±11.4%, 19 times out of 20 for the small business survey.

Sample Design

NPEI provided INNOVATIVE with confidential access to its customer lists in order to conduct this research. The customer list included information on region, electricity consumption, and preferred language for communications, as well as all available telephone numbers and email addresses.

Since only a subset of the customers on the lists have email addresses on file, INNOVATIVE has conducted a baseline analysis to see how customers with email addresses differ from the broader customer base, followed by a detailed comparison between online and telephone survey results. The following pages detail the sampling methodology used for this research.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Residential Sample

The residential telephone survey followed a stratified random sampling methodology. This is a method of sampling that involves the division of a population into smaller groups known as strata. In stratified random sampling, the strata are formed based on a group's shared attributes or characteristics (in this case, customer service area and electricity usage). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

In the telephone survey, residential customers were divided into strata based on service area populations. Within service area populations, residential customers were then divided into quartiles based on annual electricity usage to ensure the sample has a proportionate mix of customers from *low*, *medium-low*, *medium-high*, and *high* electricity usage households. Weights were applied to adjust the *observed strata* to ensure a representative customer base.

Telephone Residential Sample

Region	Unweighted N					Weighted N				
	Consumption Quartiles					Consumption Quartiles				
	Low	Medium-Low	Medium-High	High	Total	Low	Medium-Low	Medium-High	High	Total
Niagara Falls	84	84	80	87	**335**	83	83	83	83	**332**
Pelham	4	4	4	4	**16**	4	4	4	4	**16**
Lincoln	24	24	27	20	**95**	24	24	24	24	**96**
West Lincoln	15	13	15	16	**59**	14	14	14	14	**56**
Total	127	125	126	127	**505**	125	125	125	125	**500**

The online survey data has been weighted by region and consumption to ensure a representative customer base.

Online Residential Sample

Region	Unweighted N					Weighted N				
	Consumption Quartiles					Consumption Quartiles				
	Low	Medium-Low	Medium-High	High	Total	Low	Medium-Low	Medium-High	High	Total
Niagara Falls	137	164	112	132	**545**	156	156	156	156	**625**
Pelham	8	8	5	8	**29**	7	7	7	7	**27**
Lincoln	74	71	61	27	**233**	44	44	44	44	**178**
West Lincoln	44	32	36	20	**132**	27	27	27	27	**109**
Total	263	275	214	187	**939**	235	235	235	235	**939**

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Small Business Sample

Like the residential telephone survey, the **small business telephone** survey followed stratified random sampling methodology. Weights were applied to adjust the *observed strata* to ensure a representative customer base.

Telephone Small Business Sample

Region	Unweighted N					Weighted N				
	Consumption Quartiles					Consumption Quartiles				
	Low	Medium-Low	Medium-High	High	Total	Low	Medium-Low	Medium-High	High	Total
Niagara Falls / Pelham	13	12	14	10	**49**	14	14	14	14	**58**
Lincoln / West Lincoln	6	8	10	14	**38**	7	7	7	7	**29**
Total	19	20	24	24	**87**	22	22	22	22	**87**

The online survey data has been weighted by region and consumption to ensure a representative customer base.

Online Small Business Sample

Region	Unweighted N					Weighted N				
	Consumption Quartiles					Consumption Quartiles				
	Low	Medium-Low	Medium-High	High	Total	Low	Medium-Low	Medium-High	High	Total
Niagara Falls / Pelham	13	3	13	10	**39**	12	12	12	12	**47**
Lincoln / West Lincoln	4	8	12	8	**32**	6	6	6	6	**24**
Total	17	11	25	18	**71**	18	18	18	18	**71**

Demographics

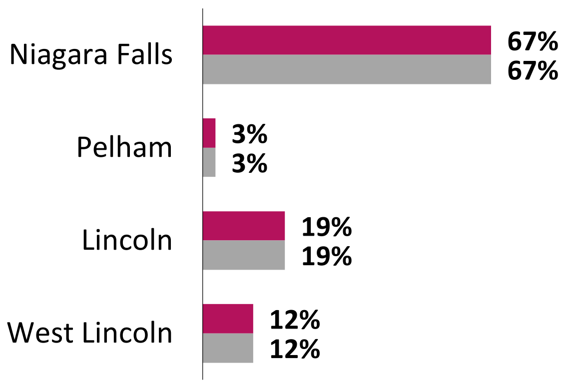
Residential Respondent Profile

Residential

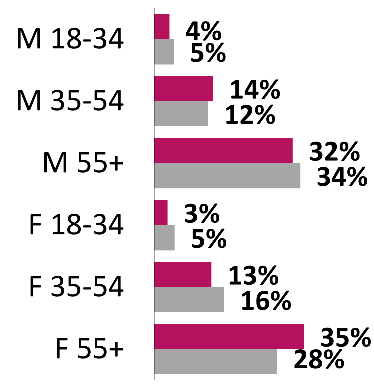
Telephone

Online

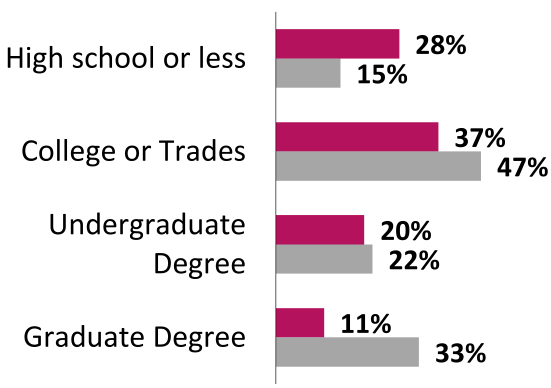
Region



Age-Gender

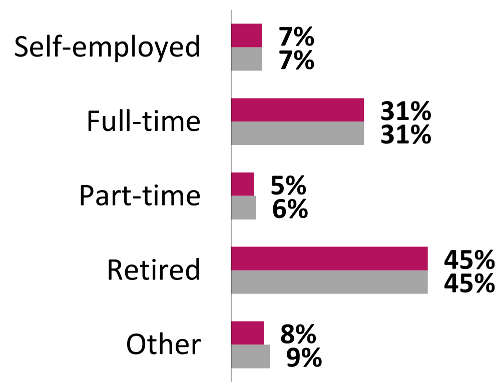


Education



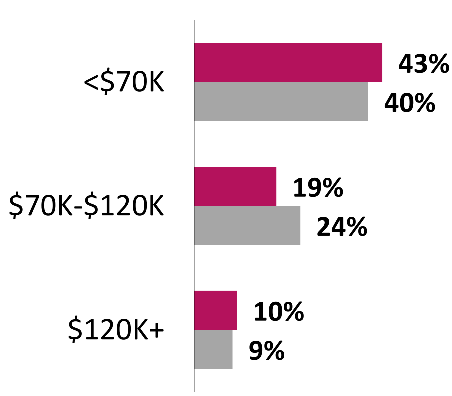
Note: 'Prefer not say' (T: 3%; O: 5%) not shown

Employment



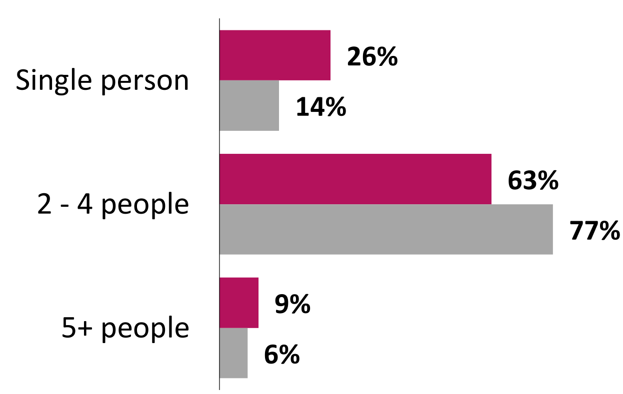
Note: 'Prefer not say' (T: 2%; O: 4%) not shown

Household Income (After Tax)



Note: 'Prefer not say' (T: 28%; O: 27%) not shown

Household Size



Note: 'Prefer not to say' (T: 3%; O: 1%) not shown

Small Business

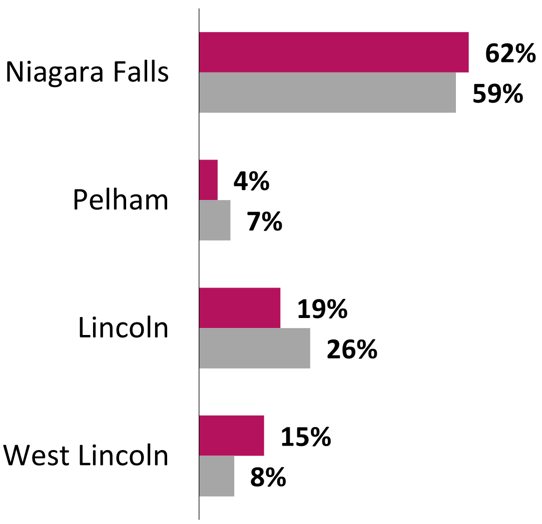
Telephone

Online

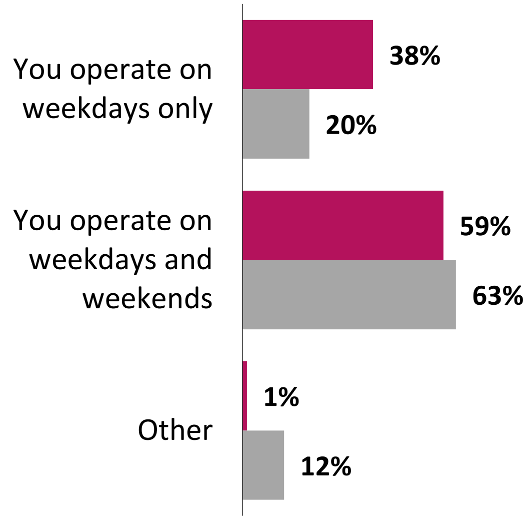
Firmographics

Small Business Respondent Profile

Region

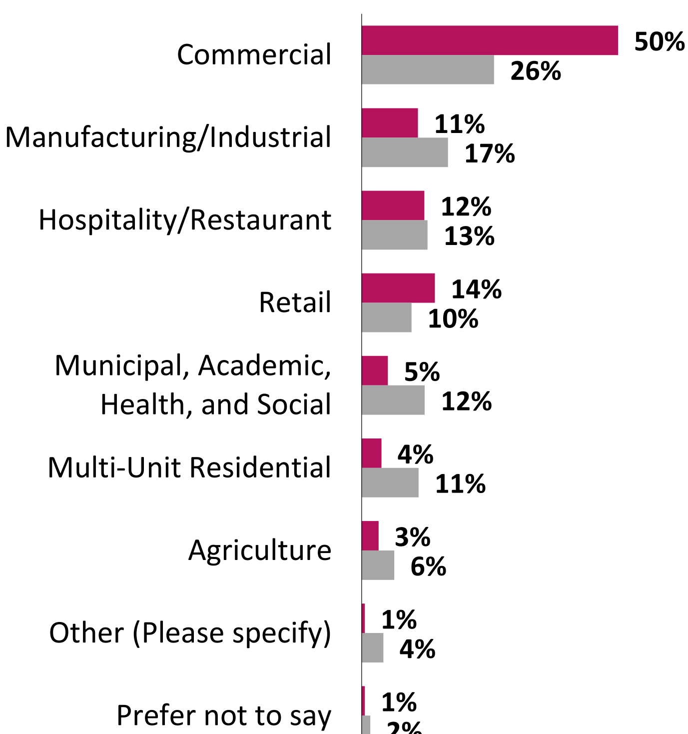


Days of operation



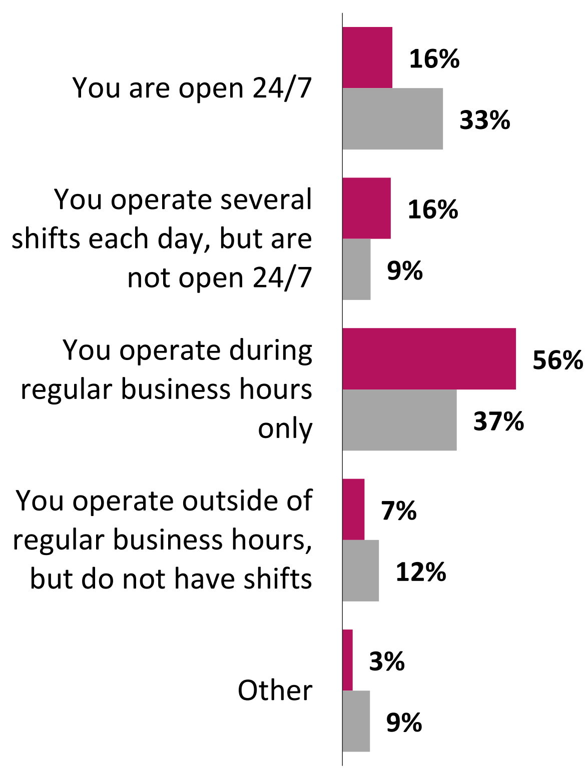
Note: 'Prefer not to say' (T: 0%; O: 6%) not shown

Sector



Note: 'Prefer not to say' (T: 1%; O: 2%) not shown

Hours of operation



Note: 'Prefer not to say' (T: 0%; O: 1%) not shown

Environmental Controls

It is important to distinguish between what is within, and what is outside of NPEI's influence or control when it comes to drivers of customer opinion.

Perceptions of distributors often tend to move with general perceptions of ***provincial government management in the sector*** rather than in response to the local utility.

In addition, perceptions of utilities are also strongly correlated with **financial circumstances**. In tough times perception and preference can change because customers are struggling with their bills, not because of anything the company has, or has not, done.

Control questions help distributors distinguish between:

a) utility driven programs that impact customer opinion; and

b) uncontrollable external drivers that impact customer opinion.

When conducting research in the energy sector, INNOVATIVE often tests multiple environmental control to assess what role predispositions (customer values and beliefs – which can be difficult and costly to change) play in the formation of opinion towards a utility.

In this study, our environmental controls focus on two key questions to help capture external phenomena:

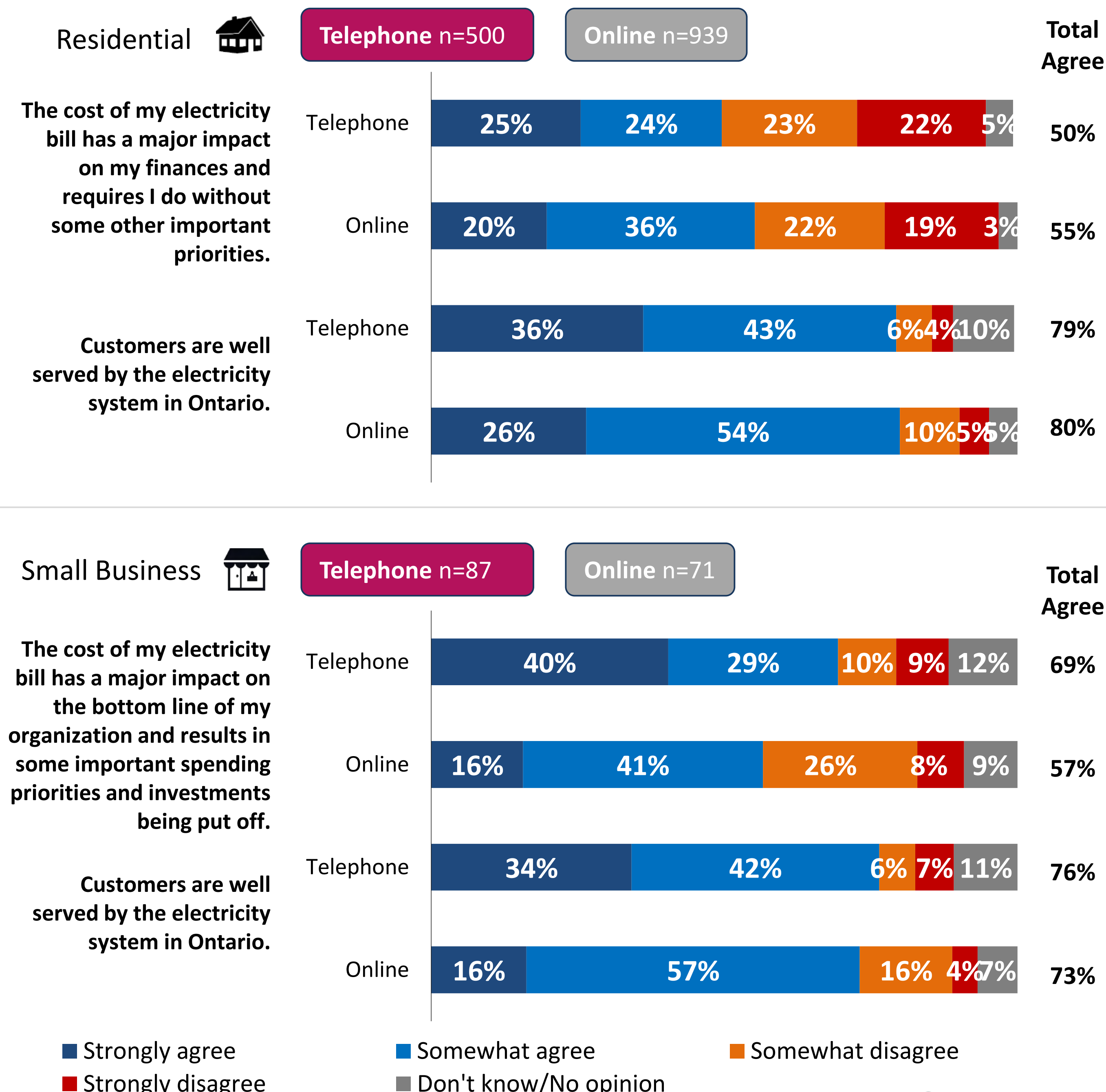
Government Management of the Electricity System: *Consumers are well served by the electricity system in Ontario.*

Financial Circumstances: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*

Environmental Controls

Customer Feedback

Q For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.



Note: Sums added before rounding. 'Refused' not shown.

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Customer Perceptions

Knowledge, CSAT, Needs

Introduction & Core Measure

Preamble

“

*The survey questions are about **Niagara Peninsula Energy** and the local electricity system in your community.*

Today we'd like to talk to you about three things:

- *We will talk about your experience with **Niagara Peninsula Energy**;*
- *We will talk about the outcomes that matter most to you; and*
- *We will talk about some trade-offs in planning future investments.*

First, let's talk about your experience.

*While you might have multiple accounts with **Niagara Peninsula Energy**, for this survey, we want you to think about your overall experience as a [residential/small business] customer.*

*The following questions are about **Niagara Peninsula Energy's** distribution system. This is the system that takes the electricity from high-voltage transmission towers and brings it to your home through a network of wires, poles and other equipment that is owned and operated by **Niagara Peninsula Energy**.*

”

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Familiarity with Niagara Peninsula Energy

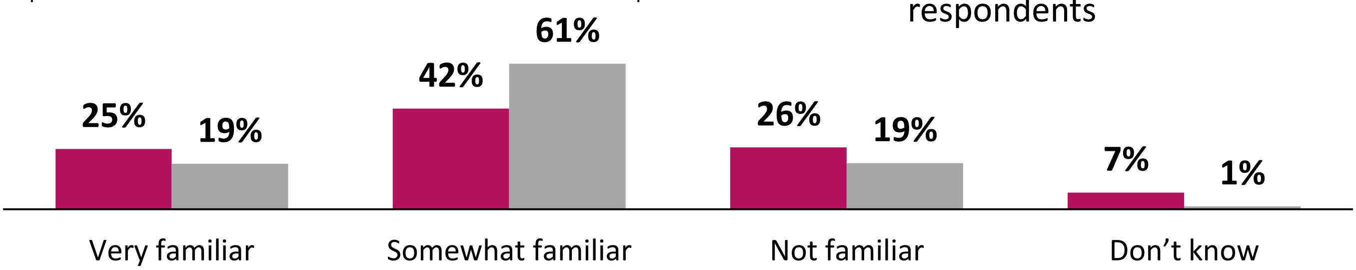
Q How familiar are you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?

Telephone | Online

Residential

Familiar
Telephone: 67%
Online: 80%

n=500 | n=939

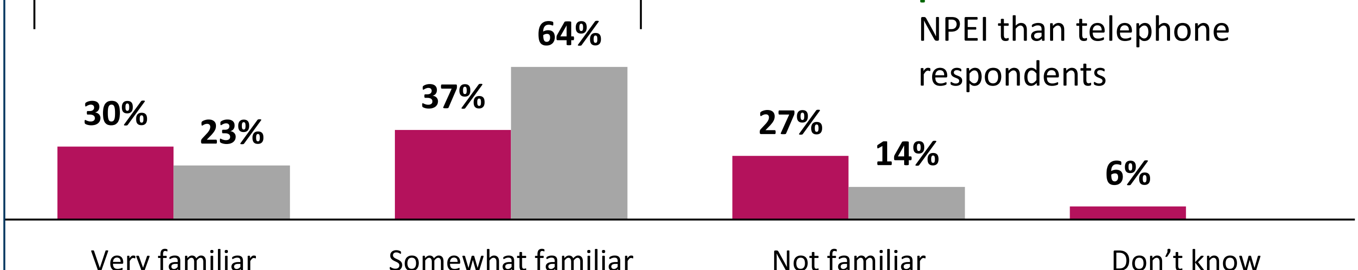


Difference:
Online are **+12 percentage points** more familiar with NPEI than telephone respondents

Small Business

Familiar
Telephone: 68%
Online: 86%

n=87 | n=71



Difference:
Online are **+18 percentage points** more familiar with NPEI than telephone respondents

Note: Sums added before rounding.

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Satisfaction with Niagara Peninsula Energy

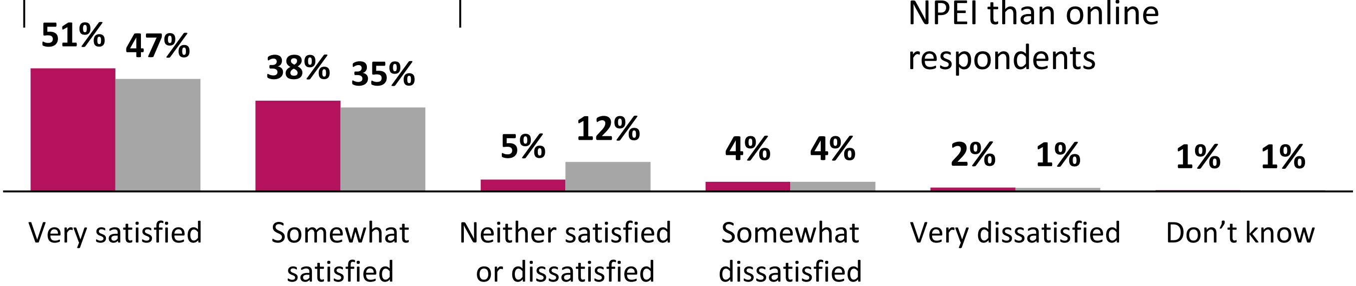
Q Thinking specifically about the services provided to you and your community by **Niagara Peninsula Energy**, overall, how satisfied or dissatisfied are you with the services that you/your organization receive? Would you say you are very satisfied, somewhat satisfied, neither satisfied nor dissatisfied, somewhat dissatisfied, very dissatisfied or would you say you don't know?

Telephone | Online

Residential

n=500 | n=939

Satisfaction
Telephone: 89%
Online: 82%

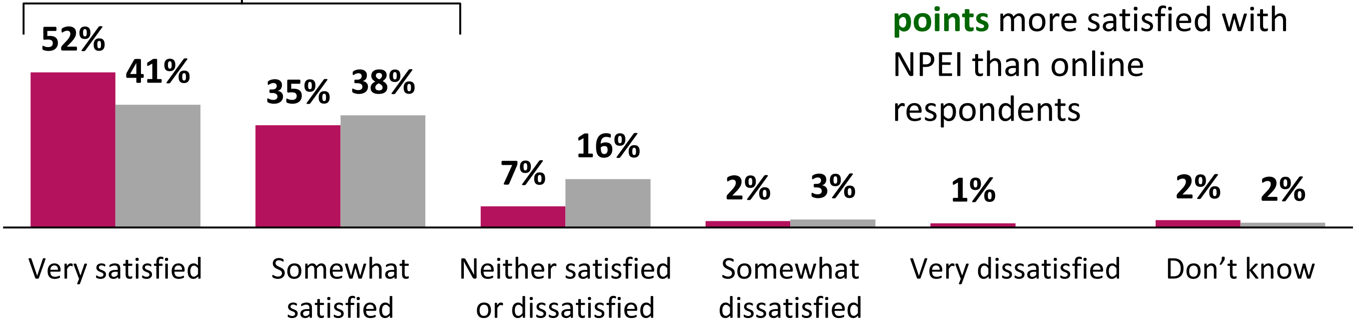


Difference:
Telephone **+7 percentage points** more satisfied with NPEI than online respondents

Small Business

n=87 | n=71

Satisfaction
Telephone: 87%
Online: 79%



Difference:
Telephone **+8 percentage points** more satisfied with NPEI than online respondents

Note: Sums added before rounding.

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Residential

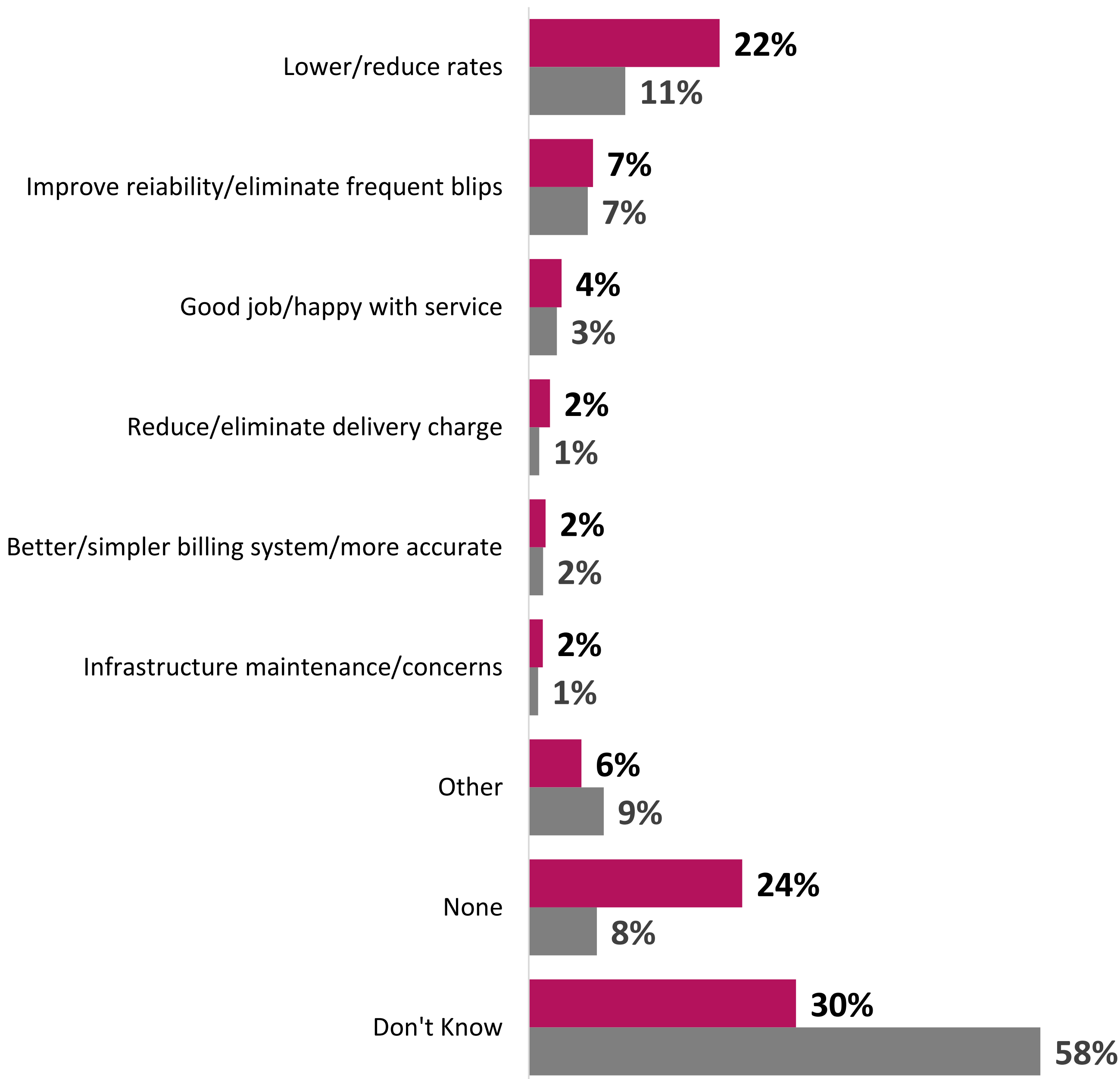
Suggestions for Improvement

Q

And, is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to you?

[asked of all respondents]

Telephone Online



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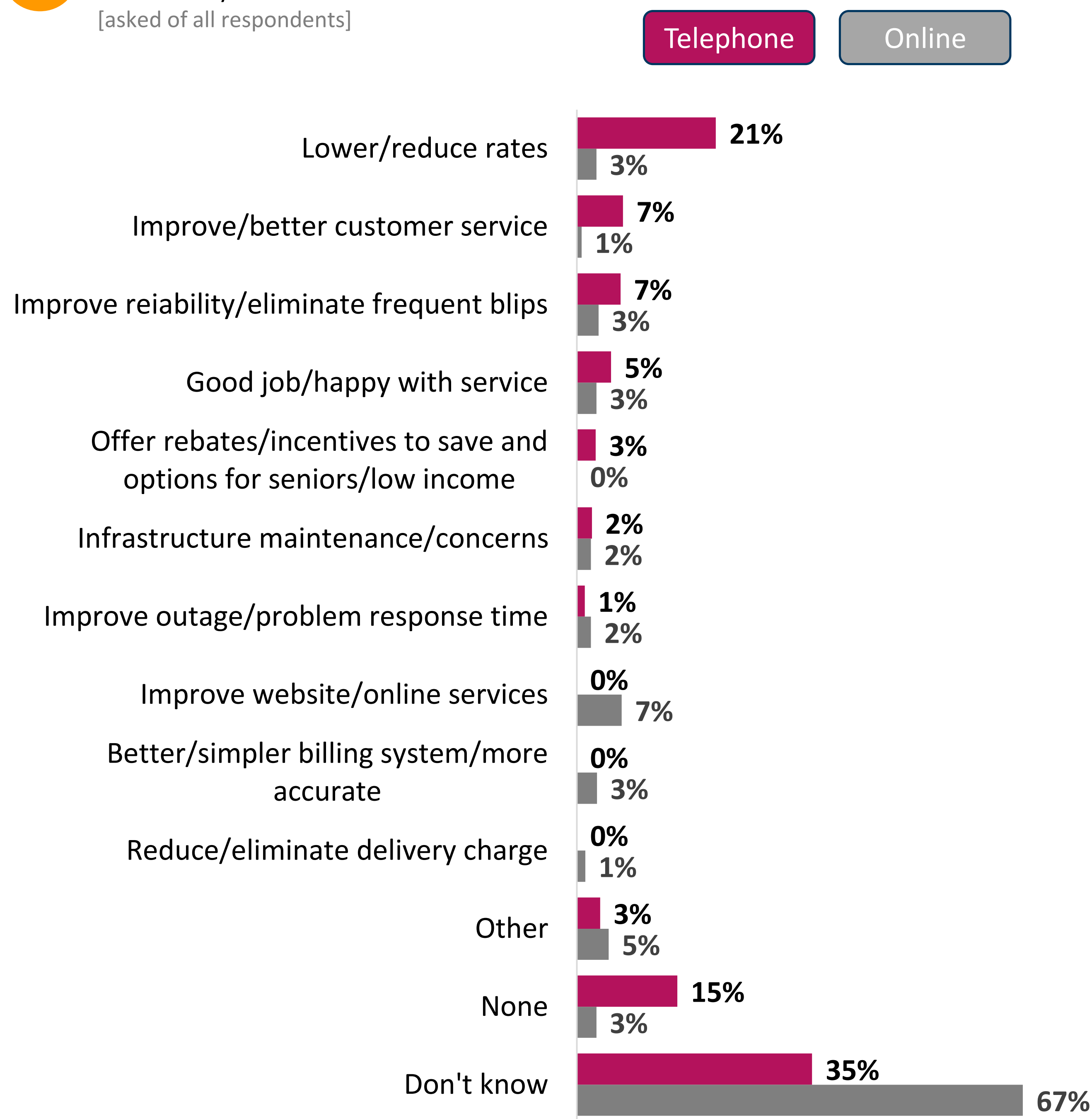
Ranked in order by telephone responses. “Other” represents responses codes <1%.

Suggestions for Improvement

Q

And, is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to you?

[asked of all respondents]



Ranked in order by telephone responses. “Other” represents responses codes <1%.

Familiarity with Share of the Bill

Preamble

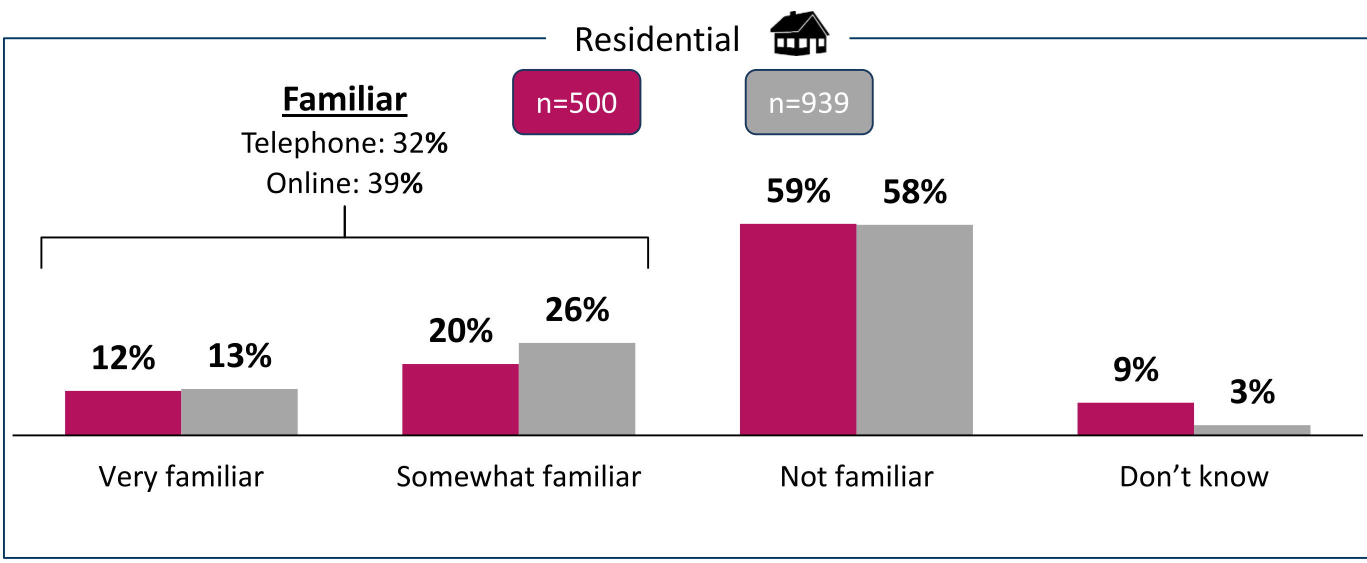
"While **Niagara Peninsula Energy** is responsible for collecting payment for the entire electricity bill, it keeps about **28%** of the average residential/small business customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies."

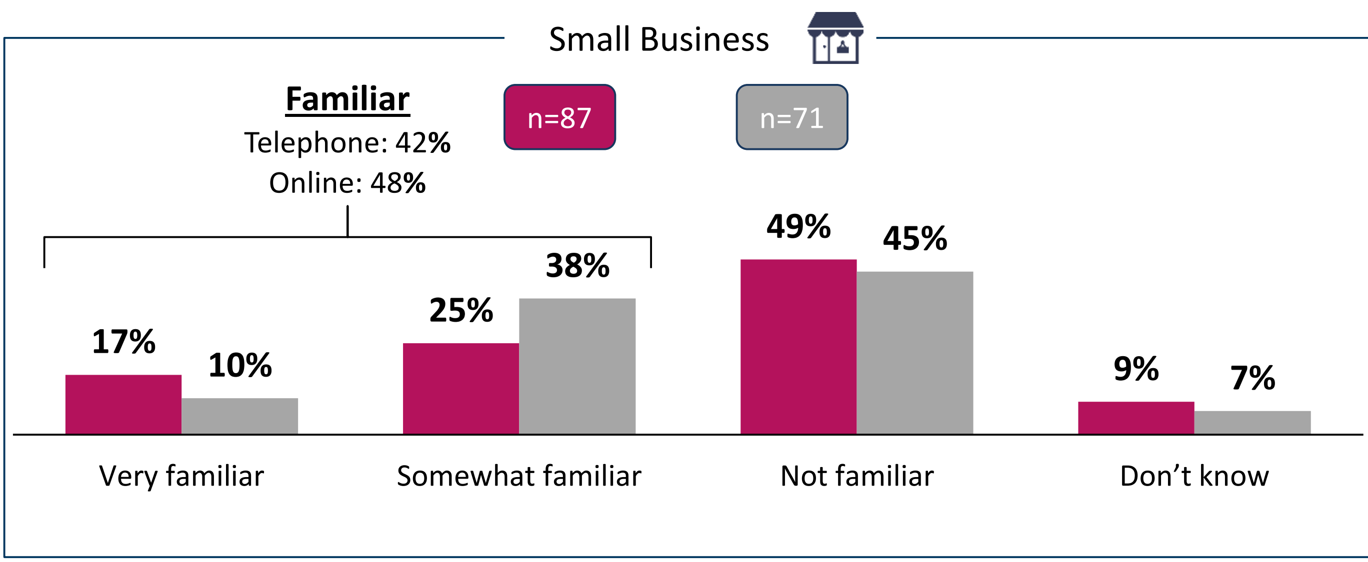
Familiarity Niagara Peninsula Energy 's Share of the Bill

Q

Before this survey, how familiar were you with the amount of your (organization's) electricity bill that went to **Niagara Peninsula Energy**? Would you say you were very familiar, somewhat familiar, not familiar or would you say you don't know?

Telephone
Online





Note: Sums added before rounding.

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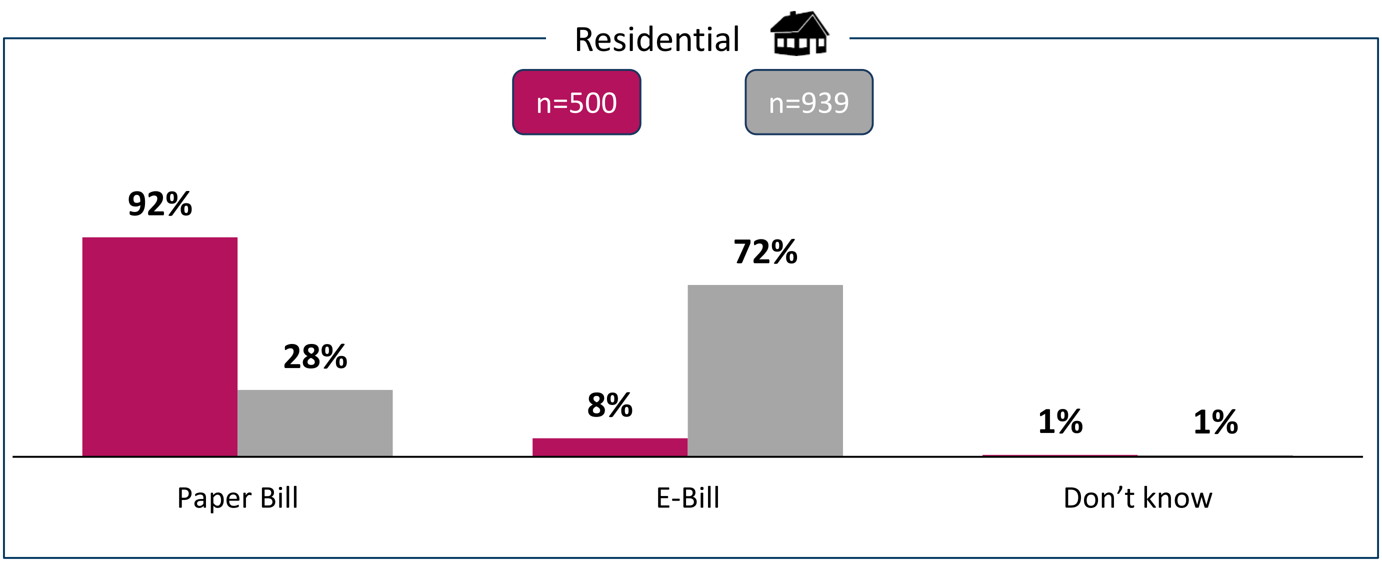
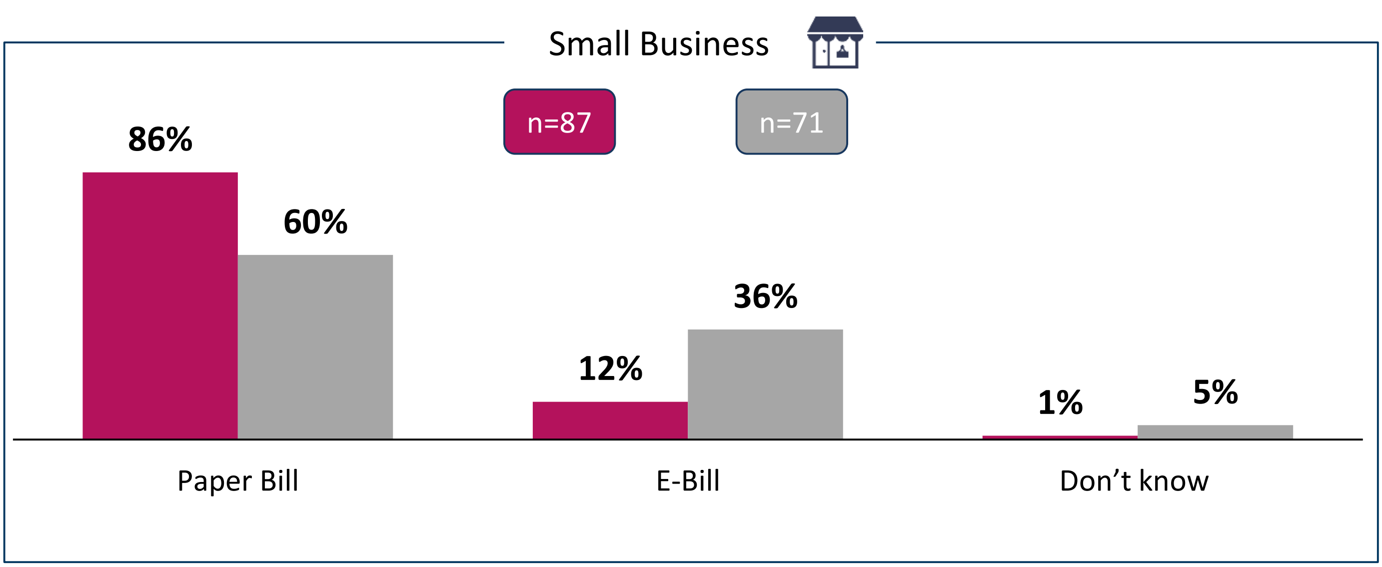
Bill Type

Q In what format do you receive your monthly bill from **Niagara Peninsula Energy**?

Telephone Online





Note: Sums added before rounding.

INNOVATIVE RESEARCH GROUP

Niagara Peninsula Energy
Customer Priorities

Customer Priorities

Preamble

“

Now, let’s talk about our second topic – outcomes.

Everyday, ***Niagara Peninsula Energy*** *interacts with hundreds of its customer through multiple channels and touchpoints, including surveys, the call centre and social media.*

In a recent series of customer focus groups, a number of company goals were identified as priorities for ***Niagara Peninsula Energy****.*

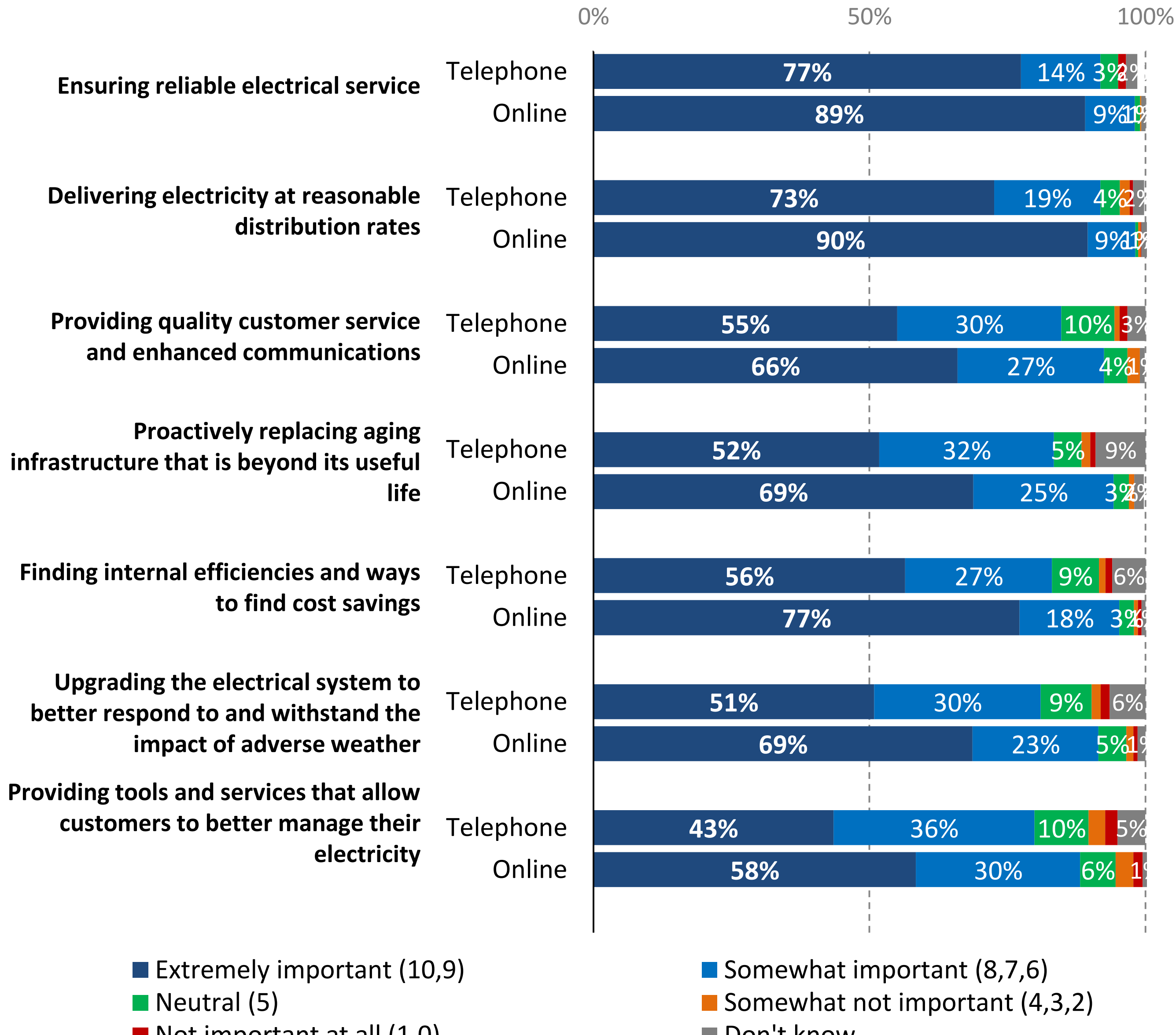
”

Residential Priorities

Overview of Importance Ratings

Q Using a scale from 0 to 10, where _0 means not important at all_ and _10 means extremely important_, how important are each of the following **Niagara Peninsula Energy** priorities to you as a customer.

[asked of all respondents, Telephone n=500; Online n=939]



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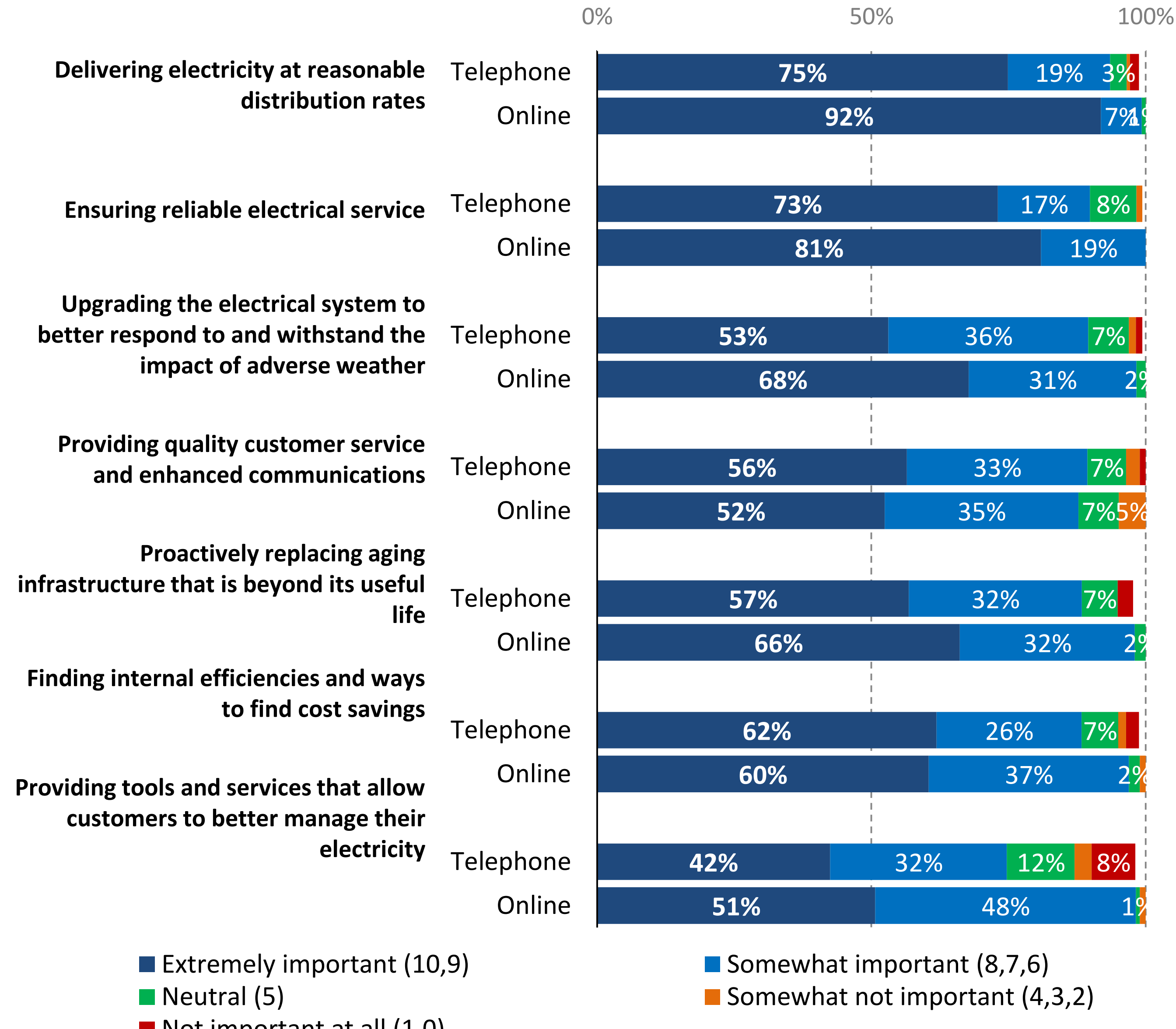
Small Business Priorities

Overview of Importance Ratings

Q

Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Niagara Peninsula Energy** priorities to you as a customer.

[asked of all respondents, Telephone n=87; Online n=71]

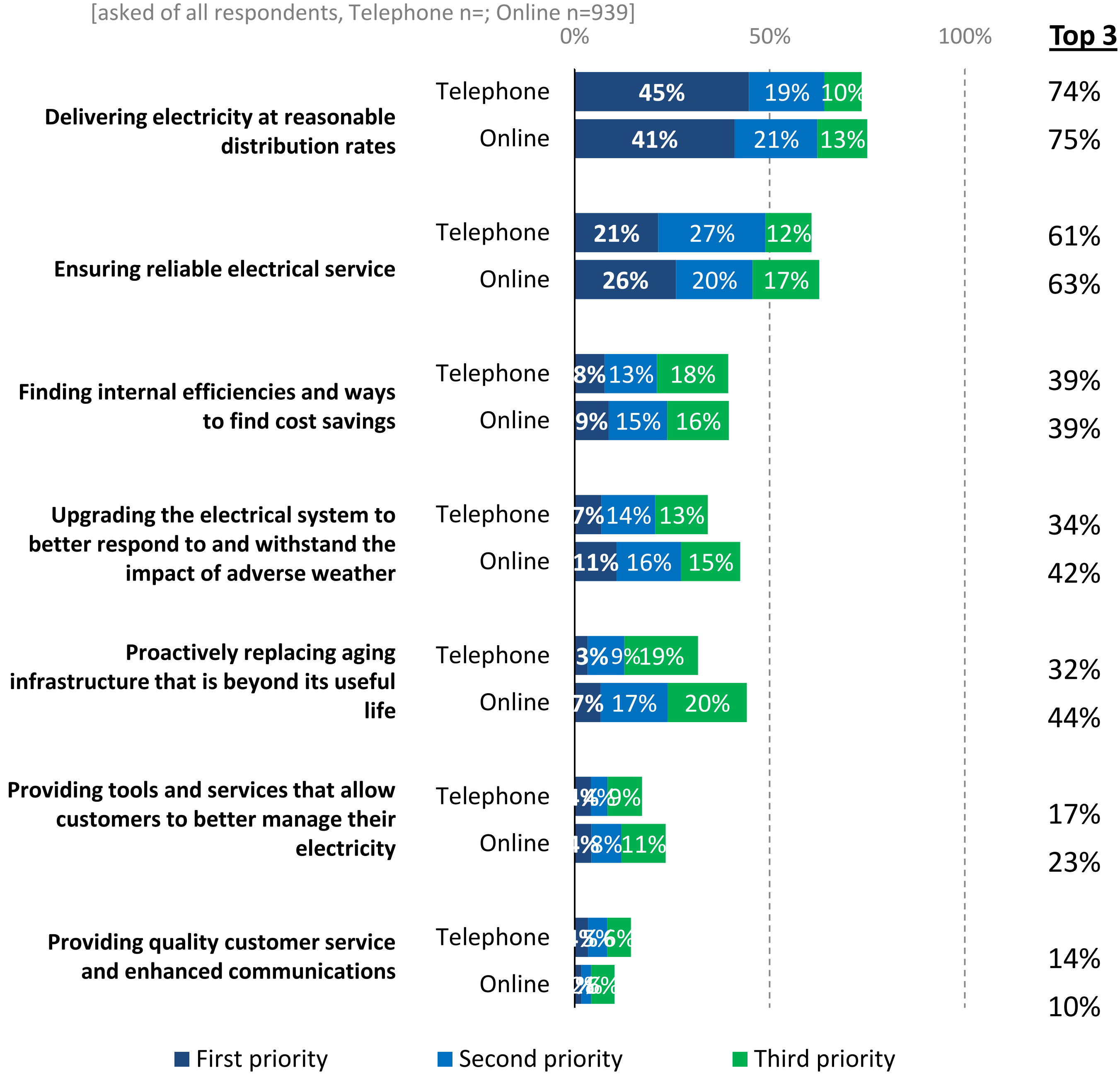


Residential Priority Rankings

Ranking the Top 3

Q Now thinking of the priorities that we just discussed, please tell me which one is most important to you. What is the next most important priority you think **Niagara Peninsula Energy** should focus on? And what do you consider the third most important priority?

[asked of all respondents, Telephone n=; Online n=939]



Note: Ranked in order by telephone responses.
"Don't know" not shown. Sums added before rounding.

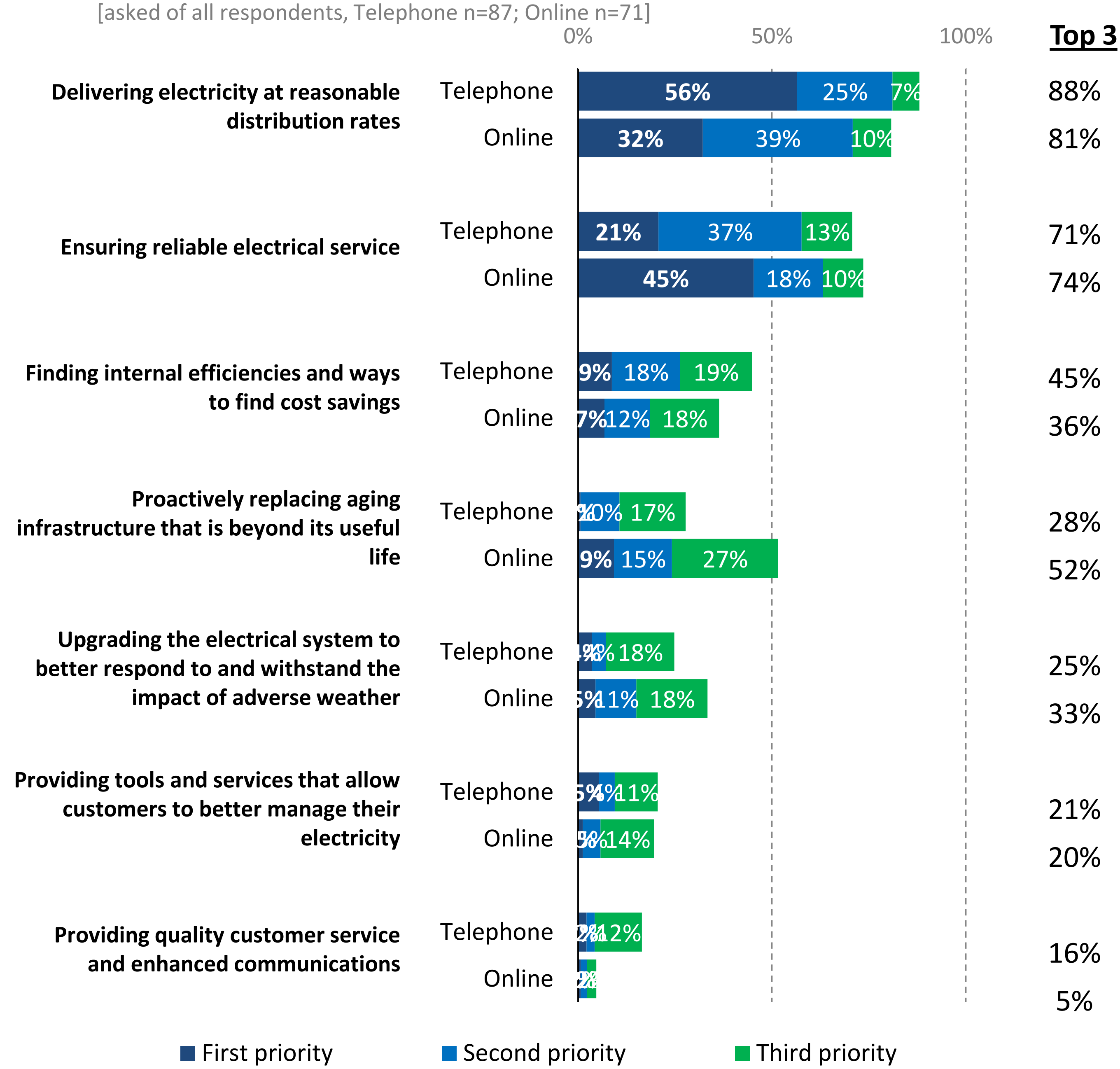
INNOVATIVE RESEARCH GROUP

Small Business Priority Rankings

Ranking the Top 3

Q Now thinking of the priorities that we just discussed, please tell me which one is most important to you. What is the next most important priority you think **Niagara Peninsula Energy** should focus on? And what do you consider the third most important priority?

[asked of all respondents, Telephone n=87; Online n=71]



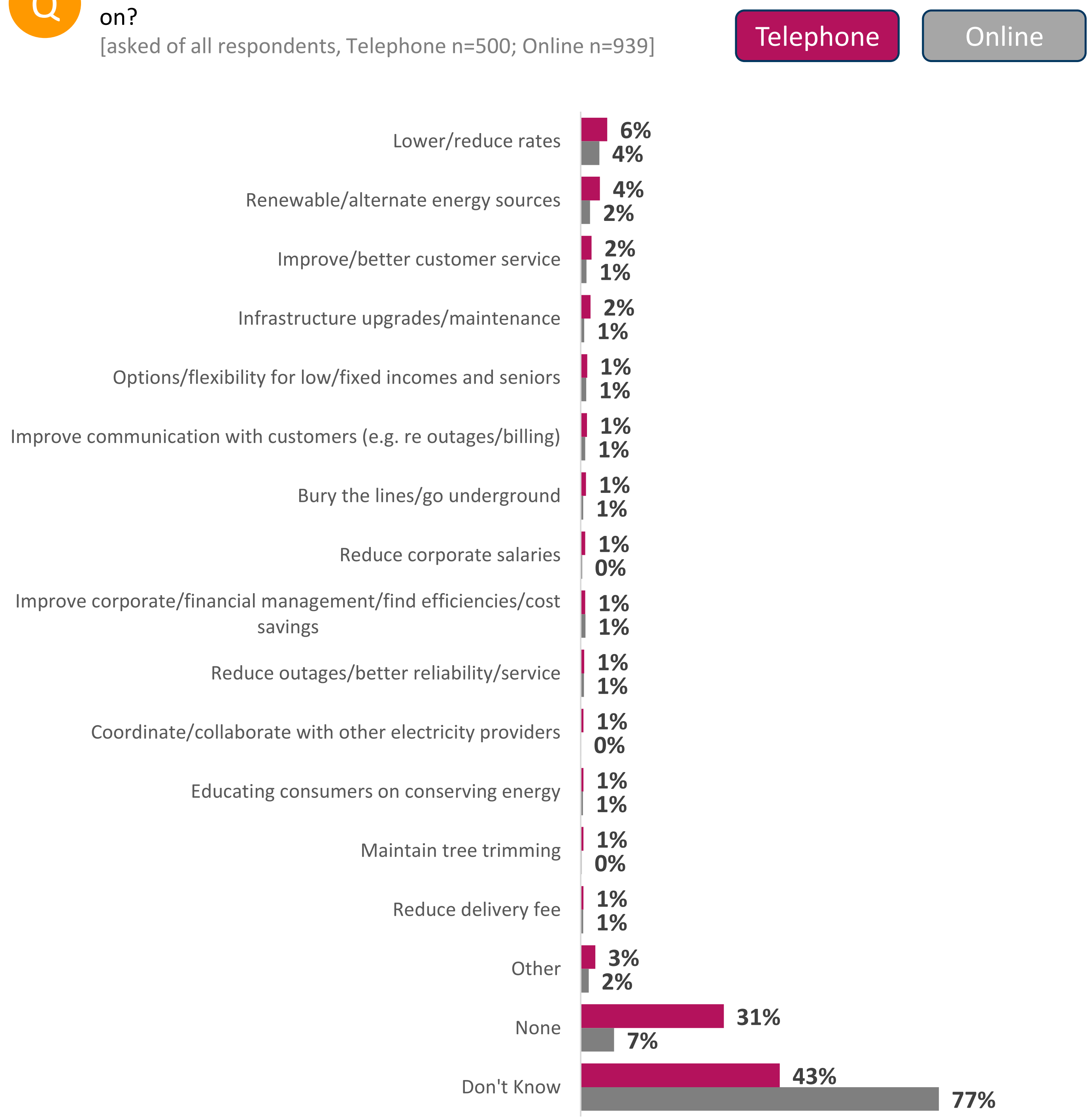
Note: Ranked in order by telephone responses.
"Don't know" not shown. Sums added before rounding.

INNOVATIVE RESEARCH GROUP

Residential

Other Important Priorities

Q Can you think of any other important priorities that **Niagara Peninsula Energy** should be focusing on?
[asked of all respondents, Telephone n=500; Online n=939]



Ranked in order by telephone responses. "Other" represents responses codes <1%.

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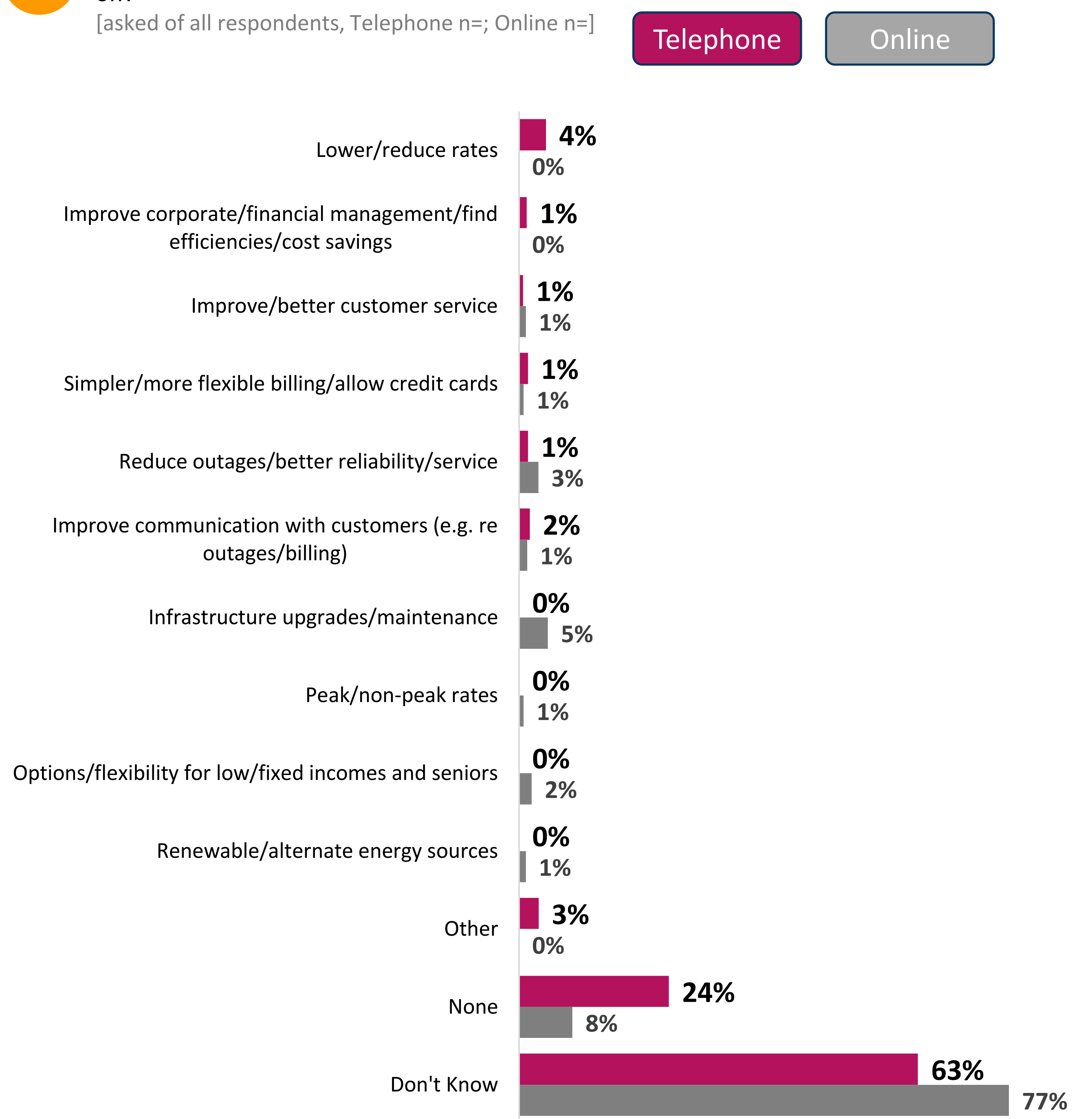
Other Important Priorities

Q Can you think of any other important priorities that Niagara Peninsula Energy should be focusing on?
[asked of all respondents, Telephone n=; Online n=]



Ranked in order by telephone responses. "Other" represents responses codes <1%.

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Reliability Outcomes

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Reliability Experience

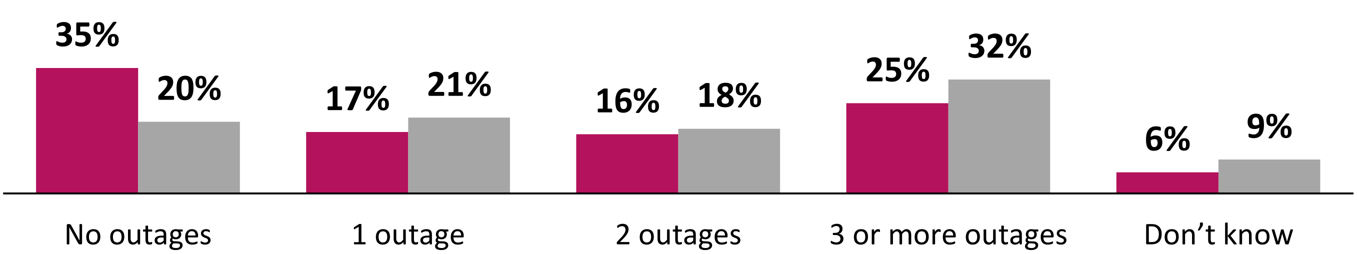
Q

Now, let's talk about the reliability of electricity service you/your organization receive. Have you experienced any power outages at **home/your organization in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you/your organization experience?

Telephone | Online

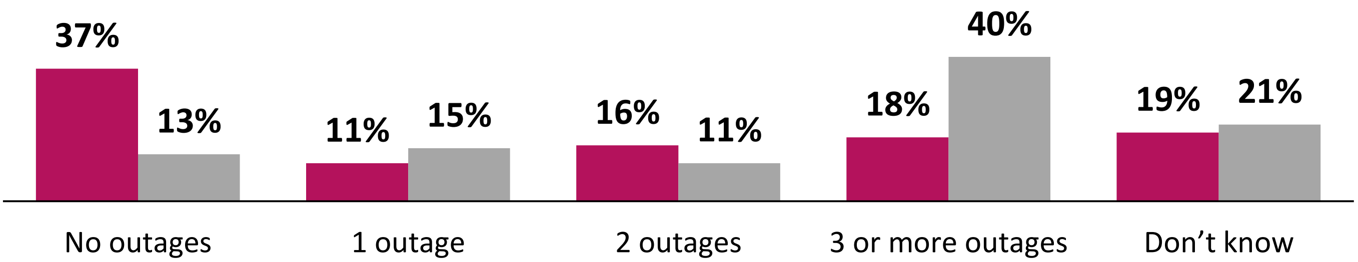
Residential

n=500 | n=939



Small Business

n=87 | n=71



Note: 'Refused' not shown.

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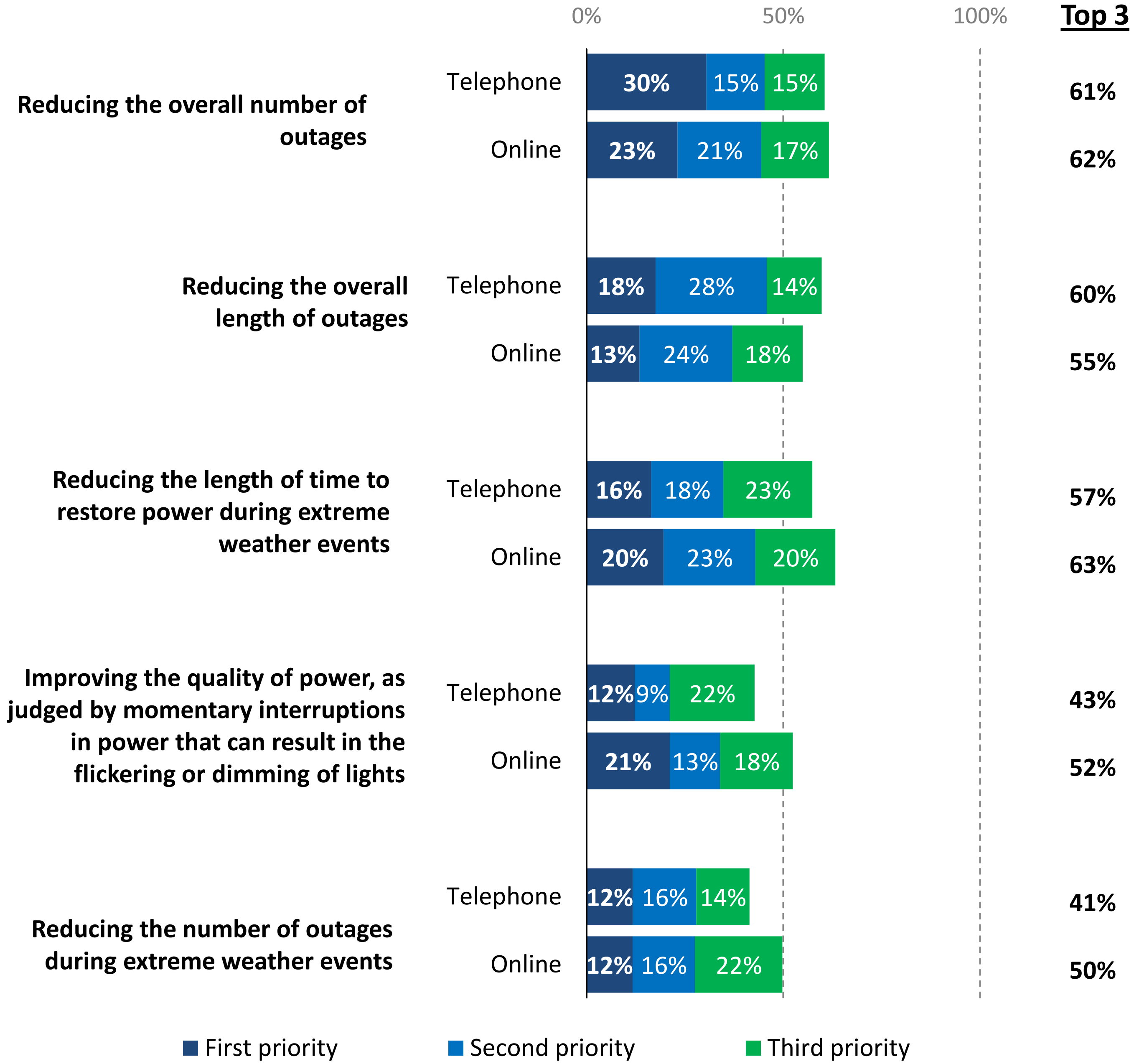
Residential

Ranking Reliability Outcomes

Ranking the Top 3

Q When it comes to reliability, there are a number of areas that **Niagara Peninsula Energy** could focus on. Among the following reliability outcomes, please tell me which one is most important to you. What is the next most important reliability outcome you think **Niagara Peninsula Energy** should focus on? And what do you consider the third most important reliability outcome?
[asked of all respondents, Telephone n=500; online n=939]



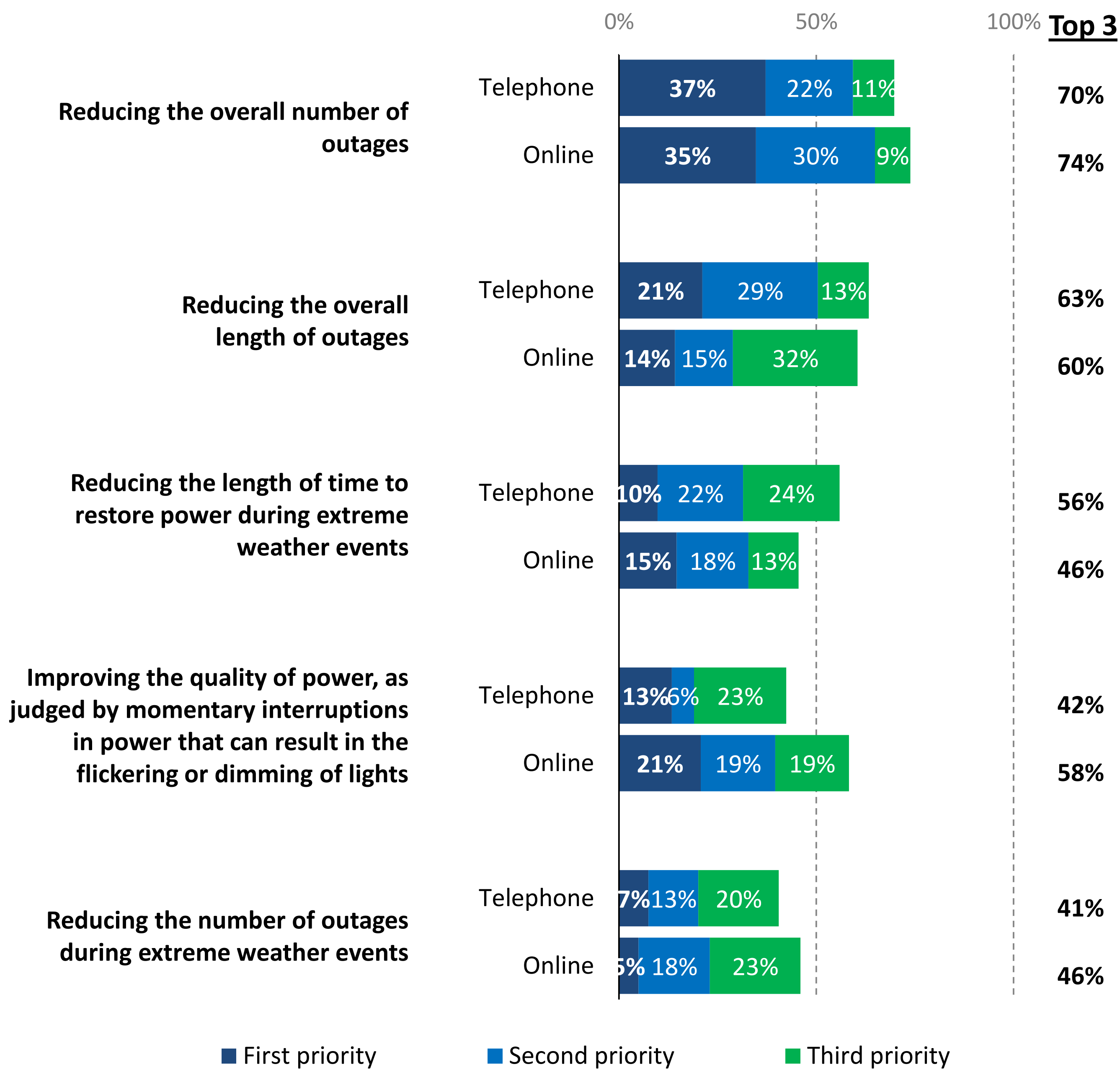
Note: Ranked in order by telephone responses.
"Don't know" not shown. Sums added before rounding.

INNOVATIVE RESEARCH GROUP

Ranking Reliability Outcomes

Ranking the Top 3

Q And when it comes to reliability, there are a number of areas that **Niagara Peninsula Energy** could focus on. Among the following reliability outcomes, please tell me which one is most important to you. What is the next most important priority you think **Niagara Peninsula Energy** should focus on? And what do you consider the third most important priority?
[asked of all respondents, Telephone n=87; Online n=71]



Note: Ranked in order by telephone responses.
"Don't know" not shown. Sums added before rounding.

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Investment Trade-Offs

Customer Priorities

Preamble

“

Now, let’s turn to our final topic – investment trade-offs.

Niagara Peninsula Energy *is in the early stages of developing its investment plan far the next five years. While conversations with customers will continue over the next several months, the utility wants to find your preferences when it comes to finding the right balance between costs and other outcomes.*

There are four investment categories that we would like to discuss.

”

System Renewal

Q The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables. Regarding investments in aging infrastructure, which of the following statements best represents your point of view?

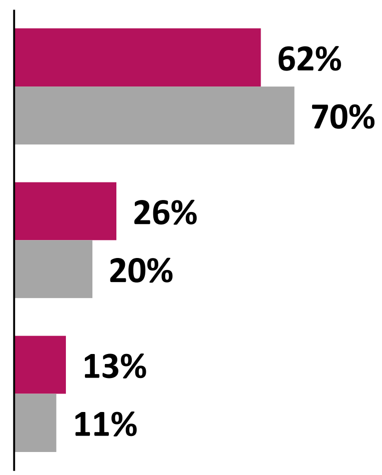
Telephone | Online

Residential

Niagara Peninsula Energy should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases my monthly electricity bill by a few dollars over the next few years

Niagara Peninsula Energy should defer its investments in replacing aging infrastructure to lessen the impact of any bill increase; even if this could eventually lead to more or longer power outages

Don't know



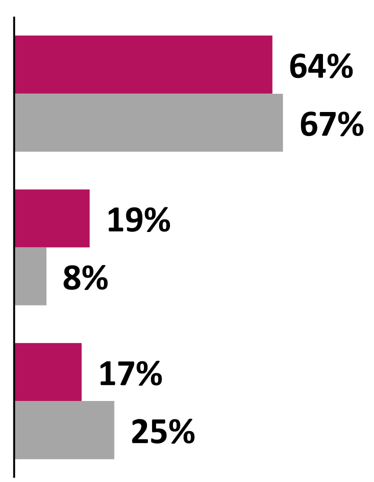
n=500 | n=939

Small Business

NPEI should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases my monthly electricity bill by a few dollars over the next few years

NPEI should defer its investments in replacing aging infrastructure to lessen the impact of any bill increase; even if this could eventually lead to more or longer power outages

Don't know



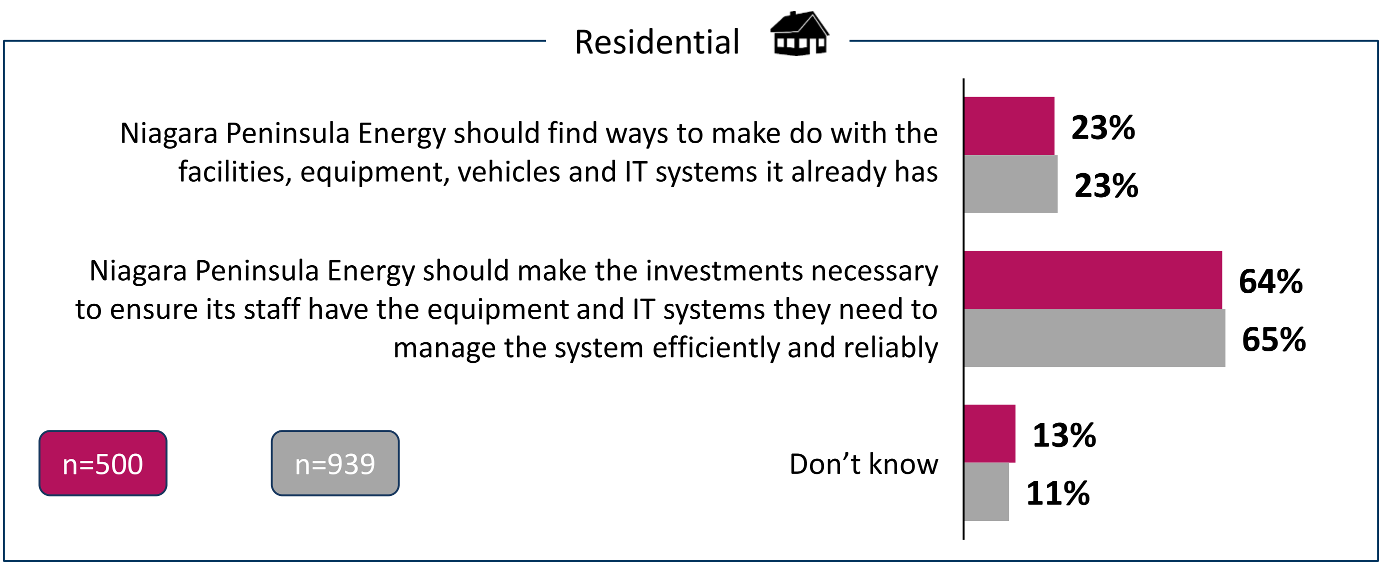
n=87 | n=71

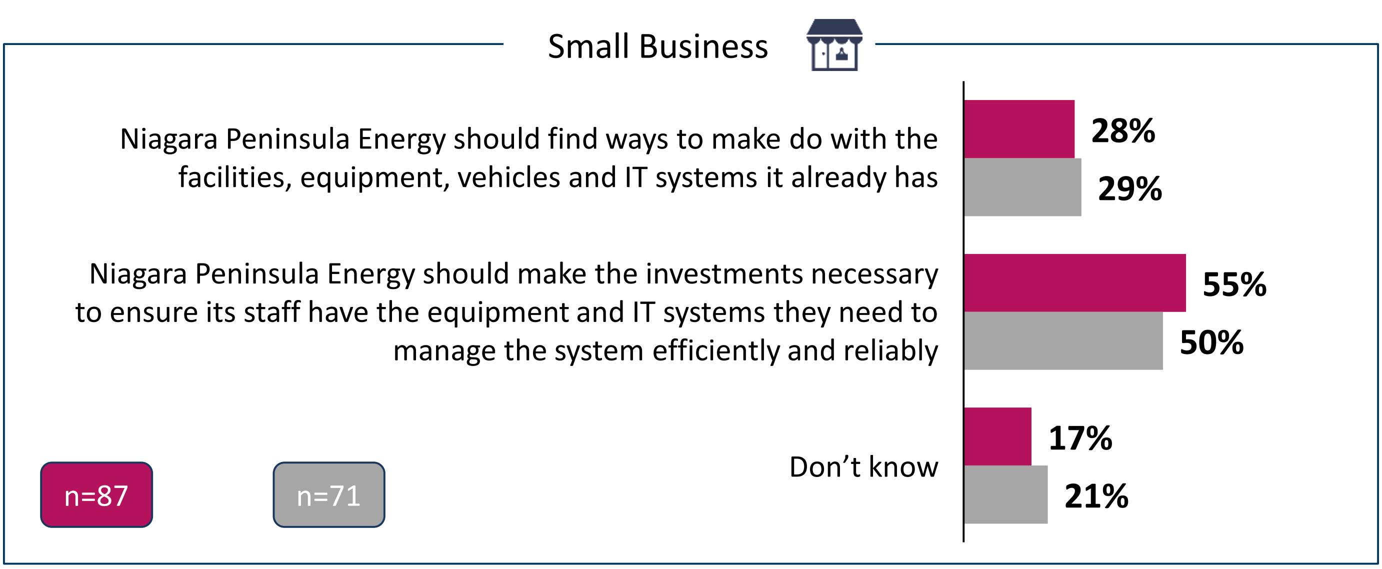
INNOVATIVE RESEARCH GROUP

General Plant

Q The second category focuses on keeping **Niagara Peninsula Energy's** business running. This includes facilities to house staff and equipment, vehicles and tools to service equipment and IT systems to manage the system and customer information. Regarding these types of investments, which of the following statements best represents your point of view?

Telephone Online



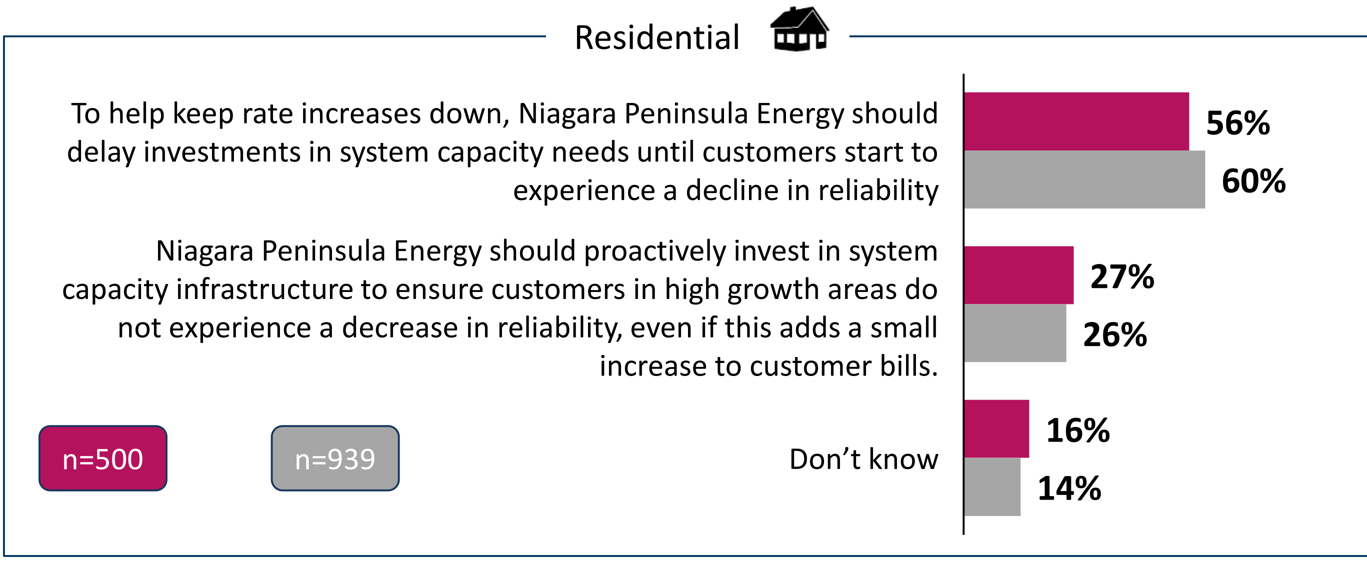


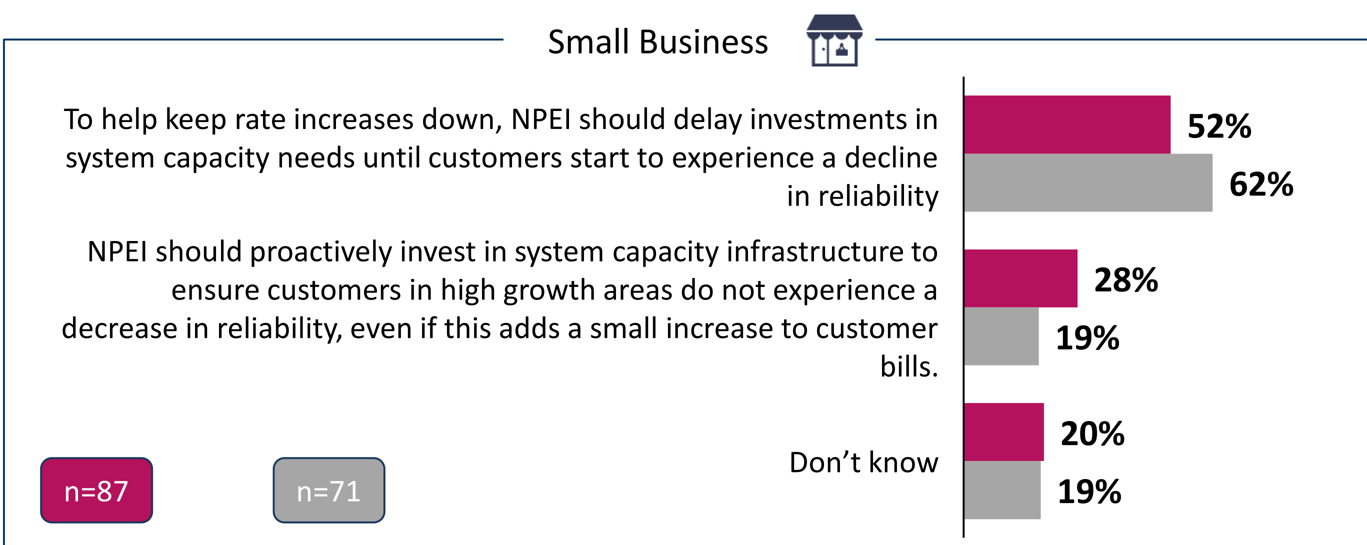
INNOVATIVE RESEARCH GROUP

System Service

Q The third investment category focuses on growth and greater demand for electricity in various parts of **NPEI's** service territory. Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity. With this in mind, which of the following statements best represents your point of view?

Telephone Online





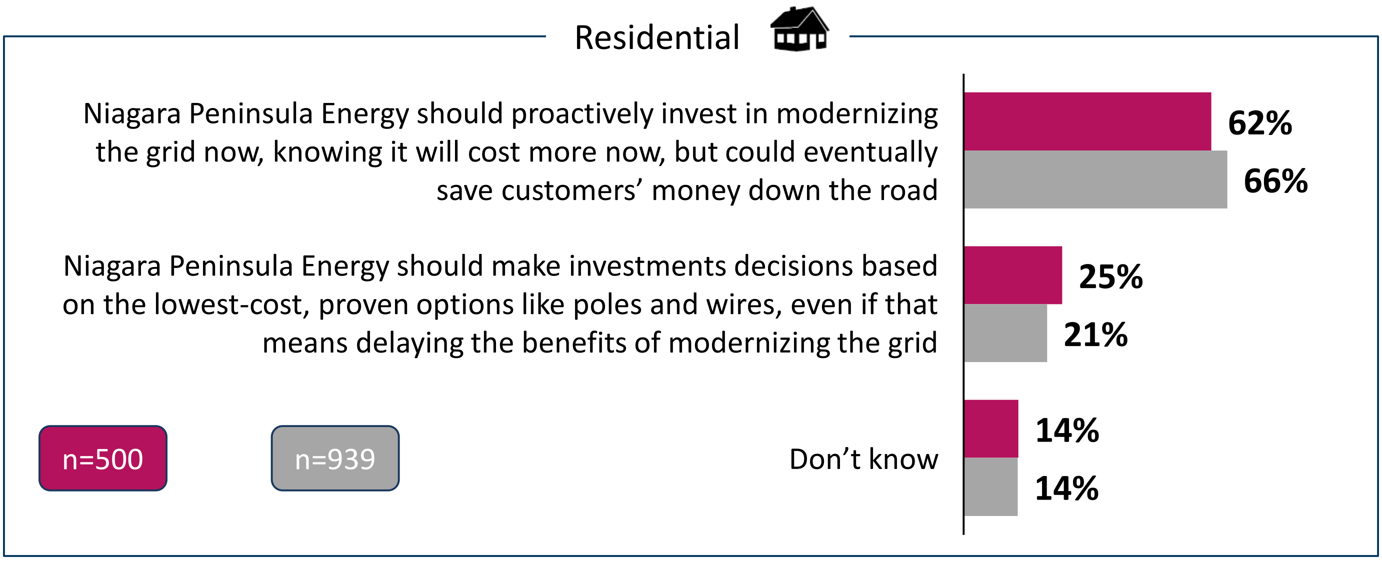
Note: 'Refused' not shown.

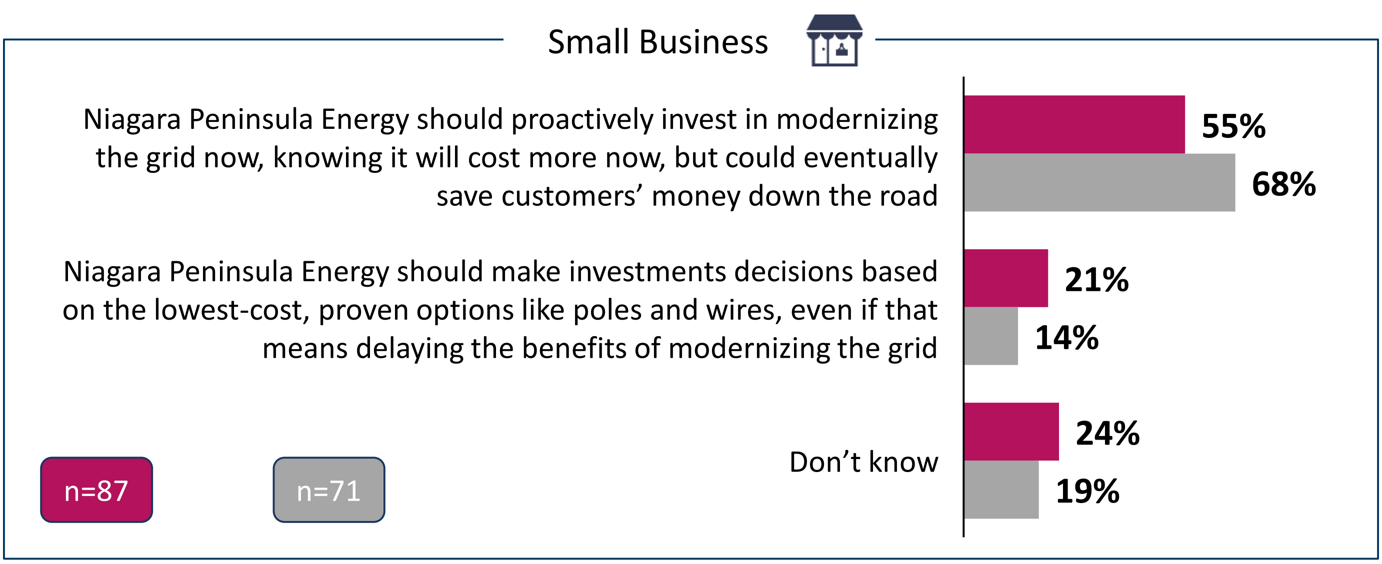
INNOVATIVE RESEARCH GROUP

Grid Modernization

Q The final category is related to new technology that **Niagara Peninsula Energy** can implement, which may eventually save customers' money down the road. These types of investments could include electricity storage, solar energy or grid automation to more easily re-route power in the case of an outage. With this in mind, which of the following statements best represents your point of view?

Telephone Online





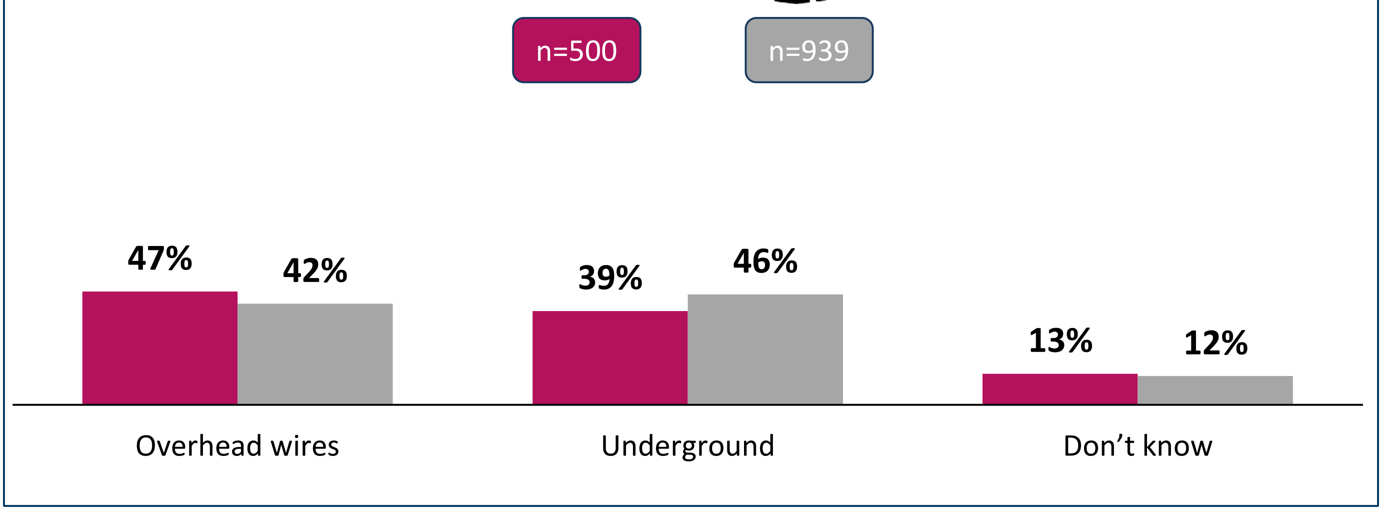
Note: 'Refused' not shown.

Connection Type

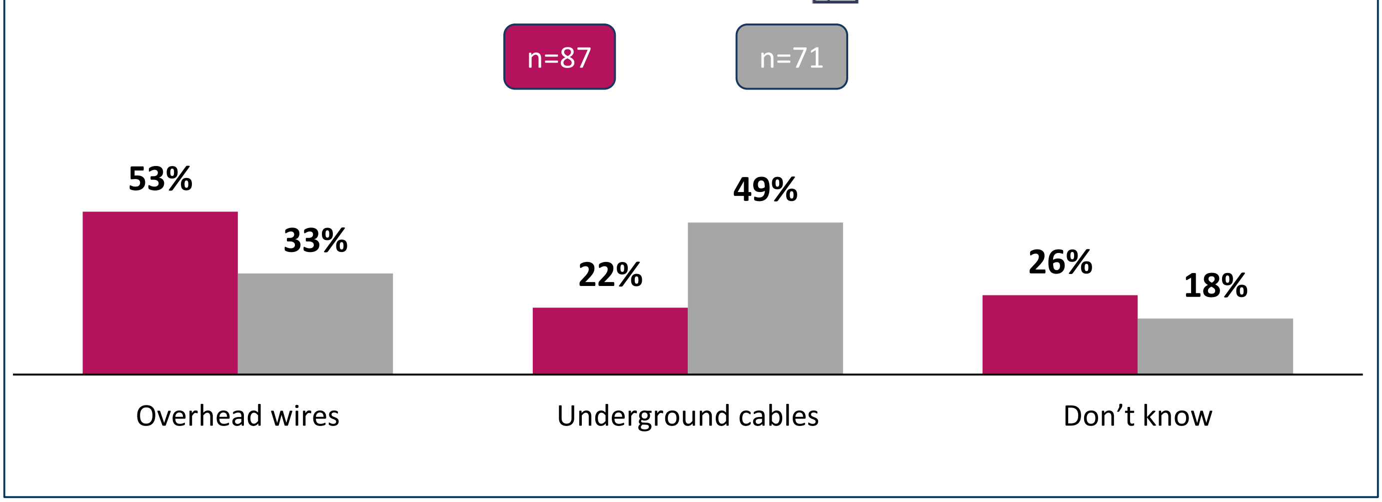
Q To the best of your knowledge, does your home receive electrical service via overhead wires, underground cables or would you say you don't know?

Telephone Online

Residential



Small Business



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Note: 'Refused' not shown.

INNOVATIVE
RESEARCH GROUP

Building Understanding.

Personalized research to connect you and your audiences.

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Customer Engagement (Appendix 3.0)

Needs and Preferences Planning Placemat

NPEI	Residential	Small business (GS<50kW)

What are customer needs?

The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates". Small business customers, however, placed greater emphasis on the lowering or reduction of rates.

	Residential	Small business (GS<50kW)
1st	Nothing	*Lower or reduce rates*
2nd	*Lower or reduce rates*	Nothing

What outcomes do customers prioritize?

Customers don't expect NPEI to just focus on one outcome. In fact, the majority of both residential and small business customers feel that almost all of the following outcomes are *extremely important* (with the exception to *providing tools to better manage electricity*).

- Ensuring reliable electrical service
- Delivering electricity at reasonable distribution rates
- Providing quality customer service and enhanced communications
- Proactively replacing aging infrastructure that is beyond its useful life
- Finding internal efficiencies and ways to find cost savings
- Upgrading the electrical system to better respond to and withstand the impact of adverse weather

Among competing outcomes, *price*, *reliability*, and *finding internal cost efficiencies* are the top three priorities for both residential and small business customers. When ranked relative to other priorities, NPEI customers see price as the top outcome that the utility should focus on.

	Residential	Small business (GS<50kW)
Top Priority	Delivering electricity at reasonable distribution rates	Delivering electricity at reasonable distribution rates
2nd Priority	Ensuring reliable electrical service	Ensuring reliable electrical service
3rd Priority	Finding internal efficiencies and ways to find cost savings	Finding internal efficiencies and ways to find cost savings

What reliability outcomes do customers prioritize?

Residential and small business customers have consistent priorities when it comes to reliability. Reducing the overall number of outages, the overall length of outages, and improving restoration time are the top three priorities for both rate classes.

	Residential	Small business (GS<50kW)
Top Priority	Reducing the overall number of outages	Reducing the overall number of outages
2nd Priority	Reducing the overall length of outages	Reducing the overall length of outages
3rd Priority	Reducing the length of time to restore power during extreme weather events	Reducing the length of time to restore power during extreme weather events

What investment trade offs do customers value most?

While keeping price at a reasonable and affordable level is an important priority for customers, the majority feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

The majority of residential and small business customers are willing to consider paying more to invest in maintaining reliability, equipping staff with equipment and IT systems, proactively investing in system capacity, and modernizing the grid knowing that it could eventually save money.

Further, the majority of customers support proactive investment in both system capacity and grid modernization. Relative to other trade offs support for investment in system capacity is least intense.

Replacing Aging Infrastructure (System Renewal)

The majority of residential and small business customers are supportive of NPEI making investments in aging infrastructure in order to maintain reliability, even if that results in small rate increases. This option is most strongly supported by small business customers, when compared to other trade offs.

% of customers who say NPEI should invest what it takes to maintain reliability

	Residential	Small business (GS<50kW)
Invest to maintain reliability	**62%**	**64%**

Keeping the Business Running (General Plant)

The majority of residential and small business customers support NPEI making the necessary investments to ensure its staff have the equipment and IT systems that are needed to manage the system efficiently and reliably. This option is most strongly supported by residential customers, when compared to other trade offs.

% of customers who say NPEI should make investments necessary in general plant

	Residential	Small business (GS<50kW)
Invest what is necessary	**64%**	**55%**

Proactive Investments in System Capacity (System Service)

A slim majority of residential and small business customers are more inclined to say that NPEI should proactively invest in system capacity infrastructure to ensure customers in high growth areas do not experience a decrease in reliability.

Relative to other trade offs, this option has the weakest level of support.

% of customers who say NPEI should proactively invest in system capacity

	Residential	Small business (GS<50kW)
Proactively invest in system capacity	**56%**	**52%**

Proactive Investments in Grid Modernization (New Technology)

The majority of residential and small business customers are supportive of NPEI proactively investing in modernizing the grid now, knowing it will cost more now, but could eventually save customers money down the road.

% of customers who say NPEI should proactively invest in modernizing the grid now

	Residential	Small business (GS<50kW)
Proactively invest in modernization	**62%**	**55%**

Customer Engagement Methodology

These findings are based on two telephone surveys conducted by Innovative Research Group among residential and GS<50kW customers.

- Field Dates: July 9 – 26, 2019
- Sample Size: n=505 residential and n=87 GS<50kW (unweighted)

Additional Information

For more information on using this document or customer engagement results, please contact:

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- **Julian Garas**: Sr. Consultant, Innovative Research Group | t: 416-640-4133 e: jgaras@innovativeresearch.ca

Telephone Reference Survey

Residential Version

July 2019

Prepared by:

Innovative Research Group, Inc.
www.innovativeresearch.ca

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A. SCREENING AND QUALIFICATIONS

Introduction

Hello, my name is ____________ and I'm calling from **Innovative Research Group** on behalf of **Niagara Peninsula Energy**, your local electricity distributor.

Innovative Research Group is a national public opinion research firm. **We're seeking your input on choices that may affect the service you receive from Niagara Peninsula Energy.**

We are simply interested in hearing your opinions – no attempt will be made to sell you anything.

A1. Do you have about **7 minutes** to answer some survey questions? All your responses will be kept strictly confidential.

1	Yes	**[continue]**
2	No – NOT PRIMARY BILL PAYER	**[go to TRANSFER-1]**
3	No – BAD TIME	**ARRANGE CALLBACK**
4	No – HARD REFUSAL	**[Terminate]**

MONIT
This call may be monitored or audio taped for quality control and evaluation purposes.

1 PRESS TO CONTINUE

CELL. Are you currently operating a car, truck or other motor vehicle?

1	YES	ARRANGE CALLBACK
2	NO	[continue to A2]
98	Refused – LOG (THANK AND TERMINATE)	**[Terminate]**

A2. Are you the person primarily responsible for paying the electricity bill in your household?

1	Yes – I pay the bill	[continue to A3]
2	Yes – shared responsibility	[continue to A3]
3	No	[go to TRANSFER-1]
98	Don't know (**DNR**)	**[Terminate]**

TRANSFER-1

Can I speak with the person in your household who usually pays the electricity bill?

1	Yes	[**BACK TO *INTRO***]
2	No – NOT AVAILABLE/BAD TIME	[ARRANGE CALLBACK]
3	No – HARD REFUSAL	[**Terminate**]
98	Don't know (**DNR**)	[**Terminate**]

A3. Can you confirm that your household receives an electricity or hydro bill from **Niagara Peninsula Energy**?

1	Yes	**[continue]**
2	No	**[Terminate]**
98	Don't know (**DNR**)	**[Terminate]**

GENDER	**Note gender by observation:**

1	Male
2	Female

A4. For statistical purposes, can you please indicate which age category you fall in? Is that … [**READ LIST**]

01	Younger than 18	**DNR**
02	18 to 24	
03	25 to 34	
04	35 to 44	
05	45 to 54	
06	55 to 64	
07	65 to 74	
08	75 or older	
99	Refused	**READ**: For this survey we need to identify customers' age. **IF STILL REFUSE**: THANK & TERMINATE

B. INTRODUCTION AND CORE MEASURE

[PREAMBLE]

Today I want to talk about **Niagara Peninsula Energy** and the local electricity system in your community.

There are three topics I would like to discuss:

- First, we will talk about your experience with Niagara Peninsula Energy.
- Second, we will talk about the outcomes that matter most to you; and
- And finally, we will talk about some trade-offs in planning future investments.

First, let's talk about your experience.

While you might have multiple accounts with Niagara Peninsula Energy, for this survey, we want you to think about your overall experience as a residential customer.

The following questions are about **Niagara Peninsula Energy's** distribution system. This is the system that takes the electricity from high-voltage transmission towers and brings it to your home through a network of wires, poles and other equipment that is owned and operated by **Niagara Peninsula Energy**.

B5. How familiar are you with **Niagara Peninsula Energy**, which operates the electricity distribution system in your community?

Would you say you are *very familiar*, *somewhat familiar*, *not familiar* or would you say you *don't know*?

01	Very familiar	
02	Somewhat familiar	
03	Not familiar	
98	Don't know	
99	Refused [**DO NOT READ**]	

B6. Thinking specifically about the services provided to you and your community by **Niagara Peninsula Energy**, overall, how satisfied or dissatisfied are you with the services that you receive?

Would you say you are *very satisfied, somewhat satisfied, neither satisfied nor dissatisfied, somewhat dissatisfied, very dissatisfied or would you say you don't know*?

01	Very satisfied	
02	Somewhat satisfied	
03	Neither satisfied or dissatisfied	
04	Somewhat dissatisfied	
05	Very dissatisfied	
98	Don't know	
99	Refused [**DO NOT READ**]	

B7. And, is there anything in particular you would like **Niagara Peninsula Energy** to do to improve its services to you? [**OPEN**]

98	Don't know	
99	Refused [**DO NOT READ**]	

B8. While **Niagara Peninsula Energy** is responsible for collecting payment for the entire electricity bill, it keeps about **28%** of the average residential customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to **Niagara Peninsula Energy**? Would you say you were *very familiar, somewhat familiar, not familiar or would you say you don't know?*

01	Very familiar
02	Somewhat familiar
03	Not familiar
98	Don't know

Bill Type

B9. And do you receive your monthly bill from Niagara Peninsula Energy as a **paper bill** or an **electronic bill**?

01	Paper Bill	
02	E-Bill	
98	Don't know [**DO NOT READ**]	

C. CUSTOMER PRIORITIES

Now, let's talk about our second topic – outcomes.

Every day, **Niagara Peninsula Energy** interacts with hundreds of its customers through multiple channels and touchpoints, including surveys, the call centre, and social media.

In a recent series of customer focus groups, a number of company goals were identified as priorities for **Niagara Peninsula Energy**.

Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Niagara Peninsula Energy** priorities to you as a customer?

Code	Response	
00	Not important at all	
01		
02		
03		
04		
05	Somewhat important	
06		
07		
08		
09		
10	Extremely important	
98	Don't know	

Randomize

C10. Delivering electricity at reasonable distribution rates

C11. Ensuring reliable electrical service

C12. Finding internal efficiencies and ways to find cost savings

C13. Upgrading the electrical system to better respond to and withstand the impact of adverse weather

C14. Proactively replacing aging infrastructure that is beyond its useful life

C15. Providing quality customer service and enhanced communications

C16. Providing tools and services that allow customers to better manage their electricity usage

End Battery

C18. Now thinking of the priorities that we just discussed, please tell me which one is most important to you. [**RANDOMIZE & READ LIST**]

01	Delivering electricity at reasonable distribution rates	
02	Ensuring reliable electrical service	
03	Finding internal efficiencies and ways to find cost savings	
04	Upgrading the electrical system to better respond to and withstand the impact of adverse weather and climate change	
05	Proactively replacing aging infrastructure that is beyond its useful life	
06	Providing quality customer service and enhanced communications	
07	Providing tools and services that allow customers to better manage their electricity usage	
98	Don't know [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

C19. What is the next most important priority you think **Niagara Peninsula Energy** should focus on?

[**Remove answer from C18. If asked, read list again**]

C20. And what do you consider the third most important priority?

[**Remove answer from C18 and C19. If asked, read list again**]

C21. Can you think of any other important priorities that **Niagara Peninsula Energy** should be focusing on? [**OPEN**]

98	Don't know [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

D. RELIABILITY OUTCOMES

D22. *Now, let's talk about the reliability of electricity service you receive.* Have you experienced any power outages at **home** **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience? [**DO NOT READ LIST**]

00	No outages	
01	1 outage	
02	2 outages	
03	3 outages	
04	4 outages	
05	5 outages	
06	6 outages	
07	7 outages	
08	8 or more outages	
98	Don't know [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

D23. And when it comes to reliability, there are a number of areas that **Niagara Peninsula Energy** could focus on. Among the following reliability outcomes, please tell me which one is most important to you. [READ LIST]

01	Reducing the overall number of outages
02	Reducing the overall length of outages
03	Reducing the number of outages during extreme weather events
04	Reducing the length of time to restore power during extreme weather events
05	Improving the quality of power, as judged by momentary interruptions in power that can result in the flickering or dimming of lights
98	Don't know [**DO NOT READ**]
99	Refused [**DO NOT READ**]

D24. What is the next most important reliability outcome you think **Niagara Peninsula Energy** should focus on?

[**Remove answer from D23 if asked to read again**]

D25. And what do you consider the third most important reliability outcome?

[**Remove answer from D23 and D24 if asked to read again**]

E. INVESTMENT TRADE-OFFS

Niagara Peninsula Energy is in the early stages of developing its investment plan for the next five years. While conversations with customers will continue over the next several months, the utility wants to find your preferences when it comes to finding the right balance between costs and other outcomes.

There are four investment categories that we would like to discuss.

System Renewal

E26. The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables.

Regarding investments in aging infrastructure, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	**Niagara Peninsula Energy** should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases my monthly electricity bill by a few dollars over the next few years
02	**Niagara Peninsula Energy** should defer its investments in replacing aging infrastructure to lessen the impact of any bill increase; even if this could eventually lead to more or longer power outages
98	Don't know

General Plant

E27. The second category focuses on keeping **Niagara Peninsula Energy's** business running. This includes facilities to house staff and equipment, vehicles and tools to service equipment, and IT systems to manage the system and customer information.

Regarding these types of investments, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	**Niagara Peninsula Energy** should find ways to make do with the facilities, equipment, vehicles and IT and computer systems it already has
02	**Niagara Peninsula Energy** should make the investments necessary to ensure its staff have the equipment and IT and computer systems they need to manage the system efficiently and reliably
98	Don't know

System Service

E28. The third investment category focuses on growth and greater demand for electricity in various parts of **Niagara Peninsula Energy's** service territory.

Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity.

With this in mind, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	To help keep rate increases down, **Niagara Peninsula Energy** should delay investments in system capacity needs until customers start to experience a decline in reliability
02	**Niagara Peninsula Energy** should proactively invest in system capacity infrastructure to ensure customers in high growth areas do not experience a decrease in reliability, even if this adds a small increase to customer bills.
98	Don't know

Grid Modernization

E29. The final category is related to new technology that **Niagara Peninsula Energy** can implement, which may eventually save customers' money down the road. These types of investments could include electricity storage, solar energy or grid automation to more easily re-route power in the case of an outage.

With this in mind, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	**Niagara Peninsula Energy** should proactively invest in modernizing the grid now, knowing it will cost more now, but could eventually save customers' money down the road
02	**Niagara Peninsula Energy** should make investments decisions based on the lowest-cost, proven options like poles and wires, even if that means delaying the benefits of modernizing the grid
98	Don't know

E30. To the best of your knowledge, does your home receive electrical service via overhead wires, underground cables or would you say you *don't know*?

01	Overhead wires	
02	Underground cables	
98	Don't know	
99	Refused [**DO NOT READ**]	

F. DEMOGRAPHICS

Lastly, I'd like to ask you some general questions about the electricity system in Ontario.

For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

01	Strongly agree
02	Somewhat agree
03	Somewhat disagree
04	Strongly disagree
98	Don't know/No opinion
99	Refused [**DNR**]

[ROTATE]

F31. The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

F32. Customers are well served by the electricity system in Ontario.

[END BATTERY]

General Demos

These final few questions are for statistical purposes only.

F33. What is the highest level of education that you have *completed*? *Would you say …* [**READ LIST**]

01	No formal schooling	
02	Some elementary or high school	
03	High school	
04	Apprenticeship or trades certificate or diploma	
05	College, CEGEP, or collège classique	
06	Bachelor's degree	
07	Degree in medicine, dentistry, veterinary medicine, or optometry	
08	Master's degree	
09	Doctorate	

F34. Which of the following categories best describes your current employment status? *Would you say …* [**READ LIST**]

01	Self-employed	
02	Employed full-time	
03	Employed part-time	
04	Seasonal employment	
05	Term employment	
06	Unemployed	
07	Student	
08	Retired	
09	Homemaker	
10	Disability/sick leave	
11	Maternity/paternal leave	
88	Other	[please specify]
99	Prefer not to say / refused [**DNR**]	

F35. Including yourself, how many people live in your household? **[DO NOT READ LIST]**]

01	Single person household	
02	2 people	
03	3 people	
04	4 people	
05	5 people	
06	6 people	
07	7 people	
08	8 people or more	
99	Prefer not to say [**DNR**]	

F36. Finally, which of the following categories best describes the total annual income, **after taxes**, of all the members of your household? *Would you say…* [**READ LIST**]

01	Less than $28,000	
02	$28,000 to less than $39,000	
03	$39,000 to less than $48,000	
04	$48,000 to less than $52,000	
05	$52,000 to less than $70,000	
06	$70,000 to less than $90,000	
07	$90,000 to less than $120,000	
09	$120,000 or more	
99	Prefer not to say	

ASK IF EMAIL==0

F37. Over the next few months, **Niagara Peninsula Energy** will be seeking further customer feedback on their plans via an online survey. Would you like us to send you an email invitation to participate in this survey? Your email will only be used for the purpose of sending you the survey.

01	Yes	
02	No	

EMAIL ASK IF F37=1

F38. And, what email would you like the survey sent to?

[ALWAYS READ BACK TO CONFIRM SPELLING]

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

Telephone Reference Survey

Small Business Ratepayer Questionnaire

July 2019

Prepared by:

Innovative Research Group, Inc.
www.innovativeresearch.ca

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Toronto, Ontario | M5E 1A7

A. SCREENING AND QUALIFICATIONS

Introduction

Hello, my name is _____________ and I'm calling from **Innovative Research Group** on behalf of **Niagara Peninsula Energy**, your local electricity distributor.

Innovative Research Group is a national public opinion research firm. **We need your input on choices that will affect the service you receive from Niagara Peninsula Energy.** Your answers will be combined with others to protect your privacy.

Can I please speak to the person who is in-charge of managing the electricity bill at your organization?

1) Yes, speaking <**contact on the line**>	**[skip to A1]**
2) Yes <**transferred to contact**>	**[skip to A1]**
3) No <**not the right contact person**>	**[GO to "NEW"]**
4) No <**busy**> "When is a good time to callback?"	**[record callback time]**
5) Maybe <**may I ask who is calling?**>	**[skip to GATE]**

NEW. And … can I have their …

First Name ___________
Last Name ___________
Title/Position _________
Phone Number _________

ASK to be transferred …

- **if transferred → go to A2**
- **if not transferred → Thank & Add to Callback List**

GATE. Hello, my name is _____________ and I'm calling from **Innovative Research** on behalf of **Niagara Peninsula Energy,** your local electricity distributor.

INTERVIEWER NOTE: If gatekeeper asks the purpose of call → I'd like to ask the person in-charge of managing the electricity bill at your organization a few questions concerning a **Niagara Peninsula Energy** customer consultation.

1) Yes <**transferred to contact**>		**[skip to A2]**
2) No <**not available**>	"*When is a good time to callback*?	**[record call-back time and go to "NEW"]**
3) No <**not interested in talking**>		**[Thank & Terminate]**

A1 QUAL PREAMBLE:

Read preamable again, if transferred to new person:

Hello, my name is ______________ and I'm calling from **Innovative Research** on behalf of **Niagara Peninsula Energy**, your local electricity distributor.

Innovative Research is a national public opinion research firm**.** We have been hired by **Niagara Peninsula Energy** to help them better understand the needs and preferences of non-residential customers who are responsible for paying their organization's electricity bill.

A1. Can I have roughly **7 minutes** of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes – I don't mind	1	[CONTINUE]
No – Not primary bill payer (i.e. not best person to speak to)	2	[go to TRANSFER]
No – BAD TIME	3	[ARRANGE CALLBACK]
No – HARD REFUSAL	4	[THANK & TERMINATE]

MONIT [INTERNAL]

This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE 1

A2. Can you confirm that your organization receives an electricity or hydro bill from **Niagara Peninsula Energy**?

YES	1	[CONTINUE]
NO	2	[THANK & TERMINATE]
DK (volunteered)	98	[THANK & TERMINATE]

A3. As part of your job, are you in charge of managing or overseeing your organization's electricity or hydro bill?

YES	1		[CONTINUE]
NO	2	"Can I speak to the person who manages your organization's electricity bill?"	[Return to **NEW**]
DK	3	"Can I speak to the person who manages your organization's electricity bill?"	[Return to **NEW**]

TRANSFER

Can I please speak to the person who is in-charge of managing the electricity bill at your organization?

Yes	1	[BACK TO *INTRO*]
No – NOT AVAILABLE/BAD TIME – (ARRANGE CALLBACK)	2	[ARRANGE CALLBACK]
No – HARD REFUSAL	3	[THANK & TERMINATE]

A4. <blank>

B. Introduction and Core Measure

[PREAMBLE]

Today I want to talk about **Niagara Peninsula Energy** and the local electricity system in your community.

There are three topics I would like to discuss:

- First, we will talk about your experience with Niagara Peninsula Energy.
- Second, we will talk about the outcomes that matter most to your organization;
- And finally, we will talk about some trade-offs in planning future investments.

First, let's talk about your experience.

While you might have multiple accounts with Niagara Peninsula Energy, for this survey, we want you to think about your overall experience as a **small business** customer.

The following questions are about **Niagara Peninsula Energy's** distribution system. This is the system that takes the electricity from high-voltage transmission towers and brings it to your organization through a network of wires, poles and other equipment that is owned and operated by **Niagara Peninsula Energy**.

B5. How familiar are you with **Niagara Peninsula Energy**, which operates the electricity distribution system in your community?

Would you say you are *very familiar*, *somewhat familiar*, *not familiar* or would you say you *don't know*?

01	Very familiar	
02	Somewhat familiar	
03	Not familiar	
98	Don't know	
99	Refused [**DO NOT READ**]	

B6. Thinking specifically about the services provided by **Niagara Peninsula Energy**, overall, how satisfied or dissatisfied are you with the services that your organization receives?

Would you say you are *very satisfied, somewhat satisfied, neither satisfied nor dissatisfied, somewhat dissatisfied, very dissatisfied or would you say you don't know*?

01	Very satisfied	
02	Somewhat satisfied	
03	Neither satisfied or dissatisfied	
04	Somewhat dissatisfied	
05	Very dissatisfied	
98	Don't know	
99	Refused [**DO NOT READ**]	

B7. And, is there anything in particular you would like **Niagara Peninsula Energy** to do to improve its services to you? [**OPEN**]

98	Don't know	
99	Refused [**DO NOT READ**]	

B8. While **Niagara Peninsula Energy** is responsible for collecting payment for the entire electricity bill, it keeps about **23%** of the average small business' bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to **Niagara Peninsula Energy**? Would you say you were *very familiar, somewhat familiar, not familiar or would you say you don't know?*

01	Very familiar
02	Somewhat familiar
03	Not familiar
98	Don't know

Bill Type

B9. And does your organization receive a monthly bill from Niagara Peninsula Energy as a **paper bill** or an **electronic bill**?

01	Paper Bill	
02	E-Bill	
98	Don't know [**DO NOT READ**]	

C. CUSTOMER PRIORITIES

Now, let's talk about our second topic – outcomes.

Every day, **Niagara Peninsula Energy** interacts with hundreds of its customer through multiple channels and touchpoints, including surveys, the call centre, and social media.

In a recent series of customer focus groups, a number of company goals were identified as priorities for **Niagara Peninsula Energy**.

Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Niagara Peninsula Energy** priorities to you as a small business customer?

Code	Response	
00	Not important at all	
01		
02		
03		
04		
05	Somewhat important	
06		
07		
08		
09		
10	Extremely important	
98	Don't know	

Randomize

C10. Delivering electricity at reasonable distribution rates

C11. Ensuring reliable electrical service

C12. Finding internal efficiencies and ways to find cost savings

C13. Upgrading the electrical system to better respond to and withstand the impact of adverse weather

C14. Proactively replacing aging infrastructure that is beyond its useful life

C15. Providing quality customer service and enhanced communications

C16. Providing tools and services that allow customers to better manage their electricity usage

End Battery

C18. Now thinking of the priorities that we just discussed, please tell me which one is most important to your organization. [READ LIST]

01	Delivering electricity at reasonable distribution rates	
02	Ensuring reliable electrical service	
03	Finding internal efficiencies and ways to find cost savings	
04	Upgrading the electrical system to better respond to and withstand the impact of adverse weather and climate change	
05	Proactively replacing aging infrastructure that is beyond its useful life	
06	Providing quality customer service and enhanced communications	
07	Providing tools and services that allow customers to better manage their electricity usage	
08	Support the local economy and community groups through new incentives programs	
98	Don’t know [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

C19. What is the next most important priority you think **Niagara Peninsula Energy** should focus on?
[**Remove answer from C18.If asked, read list again**]

C20. And what do you consider the third most important priority?
[**Remove answer from C18 and C19. Ifasked, read list again**]

C21. Can you think of any other important priorities that **Niagara Peninsula Energy** should be focusing on? [**OPEN**]

98	Don’t know [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

D. RELIABILITY OUTCOMES

D22. *Now, let's talk about the reliability of electricity service you receive.* Has your organization experienced any power outages **<u>in the past 12 months</u>** which *<u>lasted longer than one minute</u>*? If so, approximately how many of these power outages did you experience? [**DO NOT READ LIST**]

00	No outages	
01	1 outage	
02	2 outages	
03	3 outages	
04	4 outages	
05	5 outages	
06	6 outages	
07	7 outages	
08	8 or more outages	
98	Don't know [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

D23. And when it comes to reliability, there are a number of areas that **Niagara Peninsula Energy** could focus on. Among the following reliability outcomes, please tell me which one is most important to your organization. [READ LIST]

01	Reducing the overall number of outages
02	Reducing the overall length of outages
03	Reducing the number of outages during extreme weather events
04	Reducing the length of time to restore power during extreme weather events
05	Improving the quality of power, as judged by momentary interruptions in power that can result in the flickering or dimming of lights
98	Don't know [**DO NOT READ**]
99	Refused [**DO NOT READ**]

D24. What is the next most important reliability outcome you think **Niagara Peninsula Energy** should focus on?

[**Remove answer from D23 if asked to read again**]

D25. And what do you consider the third most important reliability outcome?

[**Remove answer from D23 and D24 if asked to read again**]

E. INVESTMENT TRADE-OFFS

Niagara Peninsula Energy is in the early stages of developing its investment plan for the next five years. While conversations with customers will continue over the next several months, the utility wants to find your preferences when it comes to finding the right balance between costs and other outcomes.

There are four investment categories that we would like to discuss.

System Renewal

E26. The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables.

Regarding investments in aging infrastructure, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	**Niagara Peninsula Energy** should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases your organization's monthly electricity bill by a few dollars over the next few years
02	**Niagara Peninsula Energy** should defer its investments in replacing aging infrastructure to lessen the impact of any bill increase; even if this could eventually lead to more or longer power outages
98	Don't know

General Plant

E27. The second category focuses on keeping **Niagara Peninsula Energy's** business running. This includes facilities to house staff and equipment, vehicles and tools to service equipment, and IT systems to manage the system and customer information.

Regarding these types of investments, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	**Niagara Peninsula Energy** should find ways to make do with the facilities, equipment, vehicles and IT and computer systems it already has
02	**Niagara Peninsula Energy** should make the investments necessary to ensure its staff have the equipment and IT and computer systems they need to manage the system efficiently and reliably
98	Don't know

System Service

E28. The third investment category focuses on growth and greater demand for electricity in various parts of **Niagara Peninsula Energy's** service territory.

Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity.

With this in mind, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	To help keep rate increases down, **Niagara Peninsula Energy** should delay investments in system capacity needs until customers start to experience a decline in reliability
02	**Niagara Peninsula Energy** should proactively invest in system capacity infrastructure to ensure customers in high growth areas do not experience a decrease in reliability, even if this adds a small increase to customer bills.
98	Don't know

Grid Modernization

E29. The final category is related to new technology that **Niagara Peninsula Energy** can implement, which may eventually save customers' money down the road. These types of investments could include electricity storage, solar energy or grid automation to more easily re-route power in the case of an outage.

With this in mind, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	**Niagara Peninsula Energy** should proactively invest in modernizing the grid now, knowing it will cost more now, but could eventually save customers' money down the road
02	**Niagara Peninsula Energy** should make investments decisions based on the lowest-cost, proven options like poles and wires, even if that means delaying the benefits of modernizing the grid
98	Don't know

E30. To the best of your knowledge, does your organization receive electrical service via overhead wires, underground cables or would you say you *don't know*?

01	Overhead wires	
02	Underground cables	
98	Don't know	
99	Refused [**DO NOT READ**]	

F. FIRMOGRAPHICS

Lastly, I'd like to ask you some general questions about the electricity system in Ontario.

For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

01	Strongly agree
02	Somewhat agree
03	Somewhat disagree
04	Strongly disagree
98	Don't know/No opinion
99	Refused [**DNR**]

[ROTATE]

F31. The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

F32. Customers are well served by the electricity system in Ontario.

[END BATTERY]

General Demos

These final few questions are for statistical purposes only.

F33. Which of the following best describes the sector in which your business operates? Would you say… [**READ LIST**]

01	Commercial	
02	Manufacturing/Industrial	
03	Data Centre	
04	Hospitality	
05	Restaurant/Tavern	
06	Retail	
07	Warehouse	
88	Other [Please specify:________________]	

F34. Which of the following best describes the **hours of operation** of your business? *Would you say…* [**READ LIST**]

01	You are open 24/7	
02	You operate several shifts each day, but are not open 24/7	
03	You operate during regular business hours only	
04	You operate outside of regular business hours, but do not have shifts	
88	Other [**DNR**]	[please specify]
99	Prefer not to say / refused [**DNR**]	

F35. And, which of the following best describes when your business operates throughout the week? *Would you say…* [**READ LIST**]

01	You operate on weekdays only	
02	You operate on weekdays and weekends	
88	Other [**DNR**]	[please specify]
99	Prefer not to say / refused [**DNR**]	

ASK IF EMAIL==0

F36. Over the next few months, **Niagara Peninsula Energy** will be seeking further customer feedback on their plans via an online survey. Would you like us to send you an email invitation to participate in this survey? Your email will only be used for the purpose of sending you the survey.

01	Yes	
02	No	

EMAIL ASK IF F36=1

F37. And, what email would you like the survey sent to?

[ALWAYS READ BACK TO CONFIRM SPELLING]

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

INNOVATIVE
RESEARCH GROUP

2021-2025 Rate Application

Representative Report

niagara peninsula energy inc.
Your Local Utility

This report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Niagara Peninsula Energy Inc.

January 2020

Table of Contents

Introduction

Representative Online Workbook

Niagara Peninsula Energy's 2021-2025 Rate Application Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Niagara Peninsula Energy (NPEI) to assist in meeting NPEI's customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors. The information contained within this report are the result of a series of customer engagements workbooks.

Setting the Context (Phase I)

NPEI's 2021-2025 Rate Application Customer Engagement was designed in two phases. The first phase, which was finalized in August 2019 focused on conducted parallel telephone and online surveys. Running parallel telephone and online surveys serve two primary purposes:

1. **To gather feedback and insights on the *priorities*, *preferences* and *needs* important to low-volume customers**.
   Feedback from these surveys helped NPEI planners and engineers inform the design of the utility's DSP and Business Plan, which was shared in draft, with customers in Phase II of this engagement.
2. **To establish baselines and develop weights that allowed NPEI to move to an online methodology in Phase II of this engagement.**
   Determining the baseline and understanding the difference between customers with known email addresses (email sample), and the broader customer base (telephone sample), was a critical step to migrate to a representative online survey methodology in the second phase of engagement.

Phase II Customer Engagement

NPEI is in the process of developing its 2021-2025 Rate Application. This report covers the second phase of engagement which focused on customer preferences on program timing and balancing outcomes. In order to obtain this feedback from customers, an online "workbook" was deployed to all customers with an email address, as well as promoted through a generic link on NPEI's website and social media platforms.

Interpreting the Results

For residential and small business (GS<50kW), responses were weighted by region and usage to ensure the responses were representative of the broader customer base. Due to small sample size, commercial (GS>50kW) results were not weighted and should be interpreted as directional only. Based on the comparative results of the first phase of the customer engagement, INNOVATIVE is confident that the residential and small business online workbook results contained within this report are representative of NPEI's actual customer base.

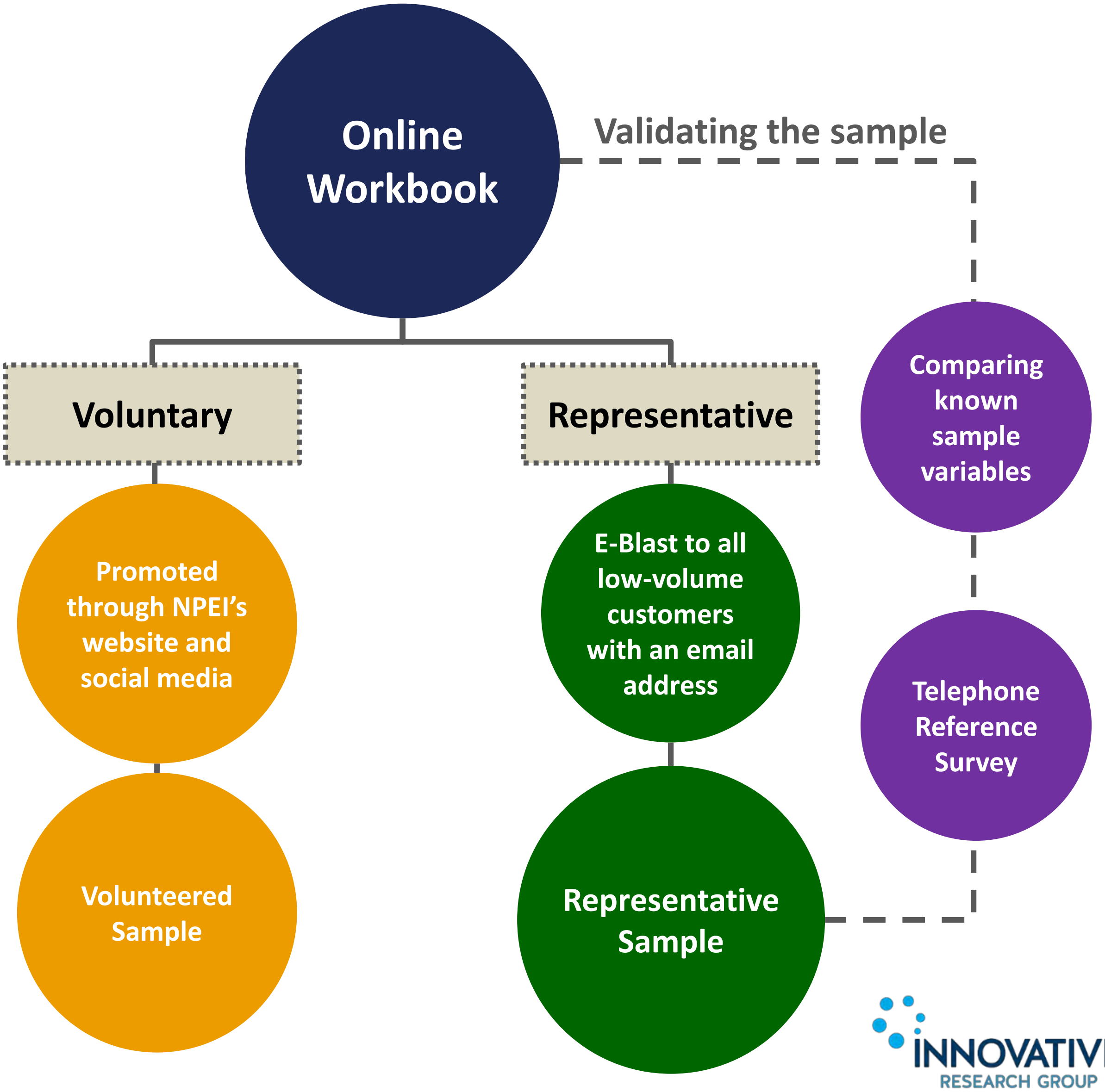
Sample Validation
Overall Approach

NPEI’s low volume (residential and small business) customer engagement workbook featured two streams – *representative* and *voluntary*.

The voluntary stream created an open process that allowed anyone who wants to be heard an opportunity to express themselves, including those who have not provided the utility with an email address. *Those results are provided in a separate report.*

The representative stream ensures a representative sample of customers are engaged, allowing for the generalizability of findings. *This is a report of those responses.*

The GS>50kW workbook was only accessible through a unique URL sent to customers. There was no voluntary stream for this version of the workbook.



Sample Validation

Email Sample vs. Broader Sample

Comparing the overall population to the sample of that population with email addresses across known variables, we can see that the email sample is largely representative of the overall population of customers.

Overall Coverage

Coverage is lower among residential customers among whom only 27% of the full population have email addresses on file, while among GS<50 customers 44% have email addresses on file. A total of 4,710 residential and 88 GS<50 customers did not have either an email address or a telephone number on file.

Rate Class	Full Population	Telephone Coverage	Email Coverage	
Residential	48,421 records	42,958 records	13,154 records	**27% of the full population**
GS<50	4,496 records	4,382 records	1,928 records	**44% of the full population**

Average Consumption

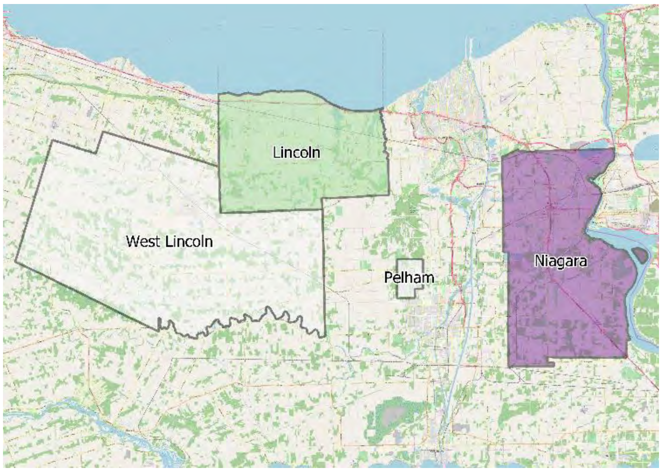
Average consumption is higher for customers in the email sample than it is among the full population for all rate classes. The largest differences exist among both groups of business customers. The final data is weighted on consumption to account for this difference.

Rate Class	Full Population	Telephone Sample	Email Sample	Diff. between email and full
Residential	700 kWh	726 kWh	727 kWh	**+4%**
GS<50	2,154 kWh	2,158 kWh	2,413 kWh	**+12%**

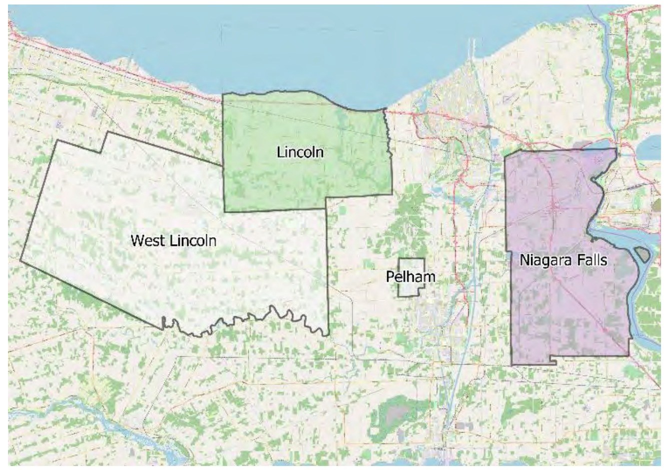
Sample Validation

Regional Analysis

Comparing the overall population to the sample of that population with email addresses across known variables, we can see that no group is substantially underrepresented in the email sample.



GS<50



Residential

Difference between the email sample and the full population
More than -5%
-5% to -2%
-2% to +2%
+2% to +5%
More than +5%

Customers are grouped into regions based on the service area listed on their account: Niagara Falls, Lincoln, West Lincoln, and Pelham.

Among residential customers, Niagara Falls as a region makes up 70% of the full population, but only 66% of the email sample. Lincoln makes up only 18% of the full population, but 21% of the email sample.

Among small business customers, the difference between the full population and the email sample is slightly larger for Niagara Falls and Lincoln. Niagara Falls is 65% of the full population and only 60% of the email sample, while Lincoln is 20% of the full population and 23% of the email sample.

The sample is stratified by region to ensure final email results reflect the real regional composition of the population

Phase I Compared to Phase II

Demographics

Comparing Phase I vs. Phase II: In Phase I, one of the core objectives was to establish baseline and understanding the difference between customers with known email addresses (email sample) and the broader customer base to migrate any potential differences in the second phase of the engagement. Comparing the results from Phase I versus Phase II showed that:

1. Overall, the Phase I and II samples look similar on key measures, particularly when it comes to general attitudes towards the electricity sector. The percentage of customers who feel that their electricity bill has a significant impact on their finances is very consistent between sample groups, giving us confidence that the samples hold very similar views towards the sector.

2. With regards to specific demographics, there appears to be a mode effect, with the telephone sample being older than the online sample.

3. There are only minor differences between the samples with regards to household income. Nothing significant that requires any weighting correction.

4. With regards to customer outage experience, again, there are slight differences, with the Phase I online sample experiencing more outages. This can be attributed to either random distribution or a system performance impact.

Gender	**Phase 1** Online	**Phase 1** Telephone	**Phase 2** Workbook
Male	51%	49%	54%
Female	49%	51%	43%
Self-identified	-	-	1%

Age	**Phase 1** Online	**Phase 1** Telephone	**Phase 2** Workbook
18-34	9%	7%	11%
35-44	13%	11%	13%
45-54	16%	16%	17%
55-64	27%	22%	24%
65 or older	35%	44%	33%

Note: sums added before rounding.

Phase I Compared to Phase II

Residential

Household Size and Income

Household Size	Phase 1 Online	Phase 1 Telephone	Phase 2 Workbook
Single person household	14%	26%	14%
2 people	50%	39%	47%
3 people	14%	14%	14%
4 people	13%	10%	14%
5 of more people	6%	9%	8%
Prefer not to say	3%	3%	3%

Household Income	Phase 1 Online	Phase 1 Telephone	Phase 2 Workbook
Less than $28,000	5%	10%	10%
$28,000 to less than $39,000	6%	10%	11%
$39,000 to less than $48,000	8%	6%	9%
$48,000 to less than $52,000	6%	7%	6%
$52,000 or more	47%	39%	42%
Prefer not to say	27%	28%	23%

Phase I Compared to Phase II

Attitudes Towards Electricity

The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.	Phase 1 Online	Phase 1 Telephone	Phase 2 Workbook
Strongly agree	20%	25%	17%
Somewhat agree	36%	24%	32%
Somewhat disagree	22%	23%	23%
Strongly disagree	19%	22%	24%
Don't know/No opinion	3%	5%	4%
Agree (Strongly + Somewhat)	**55%**	**50%**	**49%**
Disagree (Strongly + Somewhat)	**42%**	**45%**	**47%**

Customers are well served by the electricity system in Ontario.	Phase 1 Online	Phase 1 Telephone	Phase 2 Workbook
Strongly agree	26%	36%	32%
Somewhat agree	54%	43%	47%
Somewhat disagree	10%	6%	10%
Strongly disagree	5%	4%	6%
Don't know/No opinion	5%	10%	5%
Agree (Strongly + Somewhat)	**80%**	**79%**	**79%**
Disagree (Strongly + Somewhat)	**15%**	**10%**	**16%**

Phase I Compared to Phase II

Residential

Outage Experience

Number of Outages in Past Year	Phase 1 Online	Phase 1 Telephone	Phase 2 Workbook
No outages	20%	35%	24%
1 outage	21%	17%	26%
2 outages	18%	16%	20%
3 or more outages	32%	25%	21%
Don't know	9%	6%	9%

Note: sums added before rounding.

Phase I Compared to Phase II

Outage Experience

Comparing Phase I vs. Phase II: In Phase I, one of the core objectives was to establish baseline and understanding the difference between customers with known email addresses (email sample) and the broader customer base to migrate any potential differences in the second phase of the engagement. Comparing the results from Phase I versus Phase II showed that:

1. Overall, the Phase I and II samples look similar on key measures, particularly when it comes to general attitudes towards the electricity sector. Like with the residential sample, the percentage of customers who feel that their electricity bill has a significant impact on their organization's bottom line is very consistent between sample groups, giving us confidence that the samples hold very similar views towards the sector.

2. The Phase II representative workbook sample is more vulnerable than the Phase I sample, with more customers saying that the cost of their electricity bill has a major impact on the bottom line of their organization and results in some important spending priorities and investments being put off.

3. There are some differences between the number of outages that customers say that they have experienced in the past 12 months. On average, the Phase I online sample is more likely to have experienced an outage. These differences are not seen to be significant enough to warrant any weighting correction.

Number of Outages in Past Year	Phase 1 Online	Phase 1 Telephone	Phase 2 Workbook
No outages	13%	37%	22%
1 outage	15%	11%	11%
2 outages	11%	16%	33%
3 or more outages	40%	18%	26%
Don't know	21%	19%	8%

Note: sums added before rounding.

Phase I Compared to Phase II

Small Business

Attitudes Towards Electricity

The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.	Phase 1 Online	Phase 1 Telephone	Phase 2 Workbook
Strongly agree	16%	40%	29%
Somewhat agree	41%	29%	41%
Somewhat disagree	26%	10%	15%
Strongly disagree	8%	9%	13%
Don't know/No opinion	9%	12%	2%
Agree (Strongly + Somewhat)	**57%**	**69%**	**70%**
Disagree (Strongly + Somewhat)	**34%**	**19%**	**29%**

Customers are well served by the electricity system in Ontario.	Phase 1 Online	Phase 1 Telephone	Phase 2 Workbook
Strongly agree	16%	34%	26%
Somewhat agree	57%	42%	52%
Somewhat disagree	16%	6%	10%
Strongly disagree	4%	7%	9%
Don't know/No opinion	7%	11%	2%
Agree (Strongly + Somewhat)	**73%**	**76%**	**78%**
Disagree (Strongly + Somewhat)	**20%**	**13%**	**20%**

INNOVATIVE RESEARCH GROUP

Residential Customers

Online Workbook Results

Niagara Peninsula Energy Inc.
EB-2020-0040
Filed: August 31, 2020
677 of 1059

INNOVATIVE was engaged by NPEI to gather input on preferences on program timing and balancing outcomes. **Pages 15 to 68** show the actual pages of the workbook that was sent and completed by customers. The only additions are the actual results.

Field Dates & Workbook Delivery

The **Residential Online Workbook** was sent to all Niagara Peninsula Energy residential customers who have provided the utility with an email address. Customers had an opportunity to complete the workbook between **November 21st and December 17th, 2019**.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the residential workbook was sent to **11,962** customers via e-blast from INNOVATIVE.

Residential Online Workbook Completes

A total of **1,264** (unweighted) Niagara Peninsula Energy residential customers completed the online workbook via a unique URL.

Sample Weighting

The residential online workbook sample has been weighted proportionately by region and consumption quartiles in order to be representative of the broader Niagara Peninsula Energy service territory.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by region and quartile.

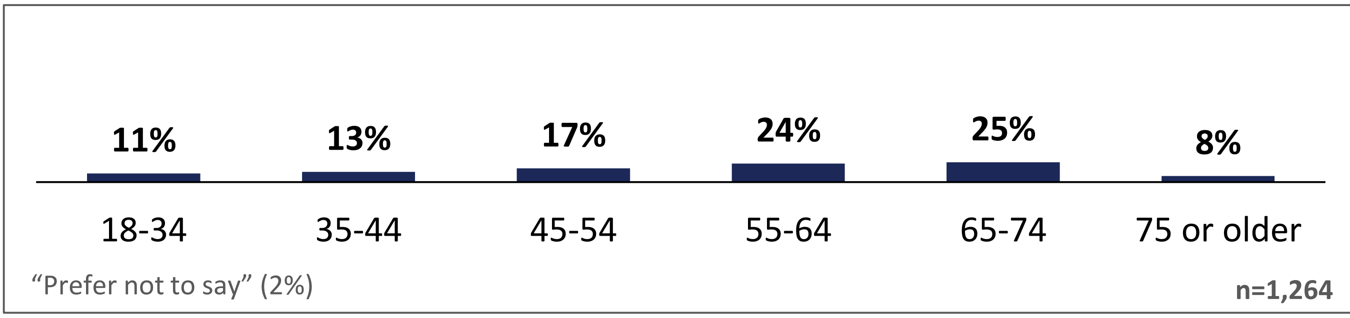
Region	Consumption Quartiles				Total	Distribution
	Low	Medium-Low	Medium-High	High		
Niagara Falls	215 (210)	224 (210)	192 (210)	134 (210)	765 (839)	61% (66%)
Pelham	15 (10)	14 (10)	12 (10)	9 (10)	50 (40)	4% (3%)
Lincoln	60 (61)	67 (61)	65 (61)	86 (61)	278 (243)	22% (19%)
West Lincoln	19 (35)	45 (35)	40 (35)	67 (35)	171 (142)	14% (11%)
Total	309 (316)	350 (316)	309 (316)	296 (316)	1,264 (1,264)	**100%**

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

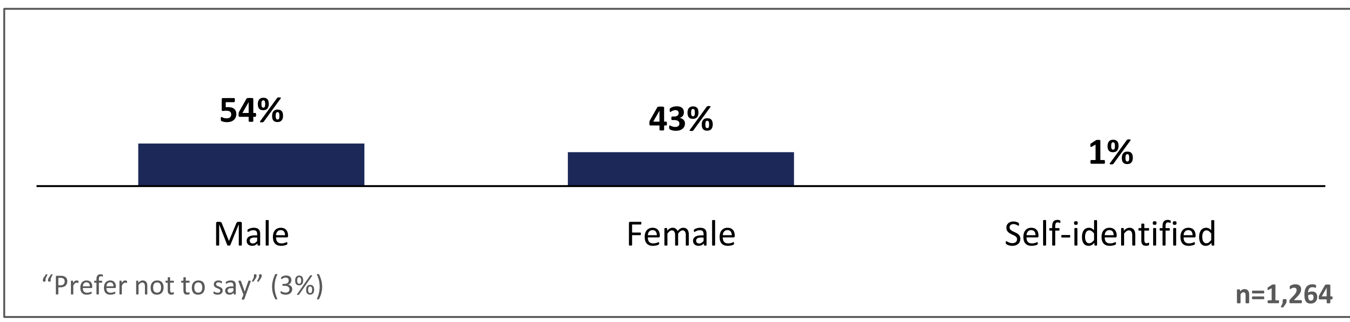
Representative Workbook

Demographic Breakdown

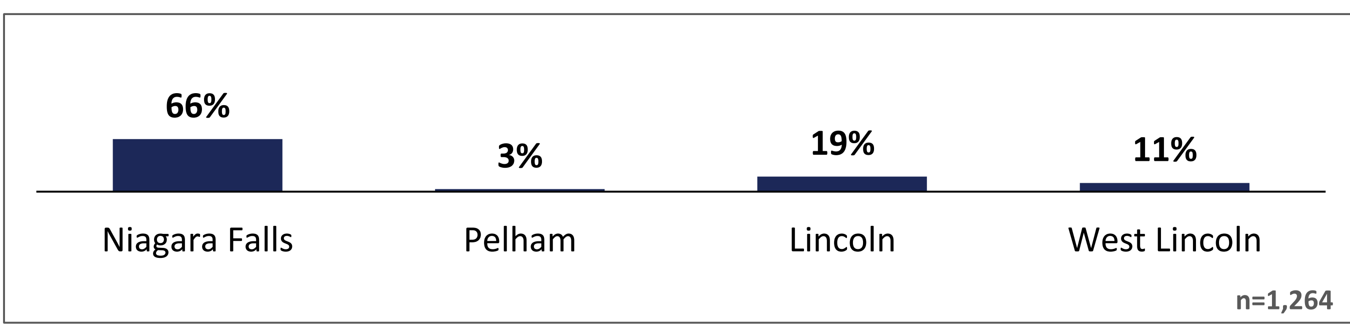
Q Age



Q Gender



Q Region

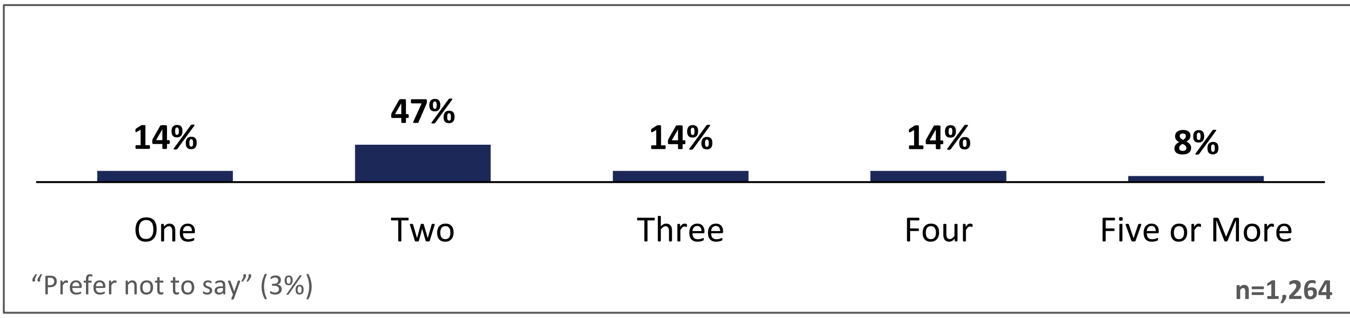


Representative Workbook

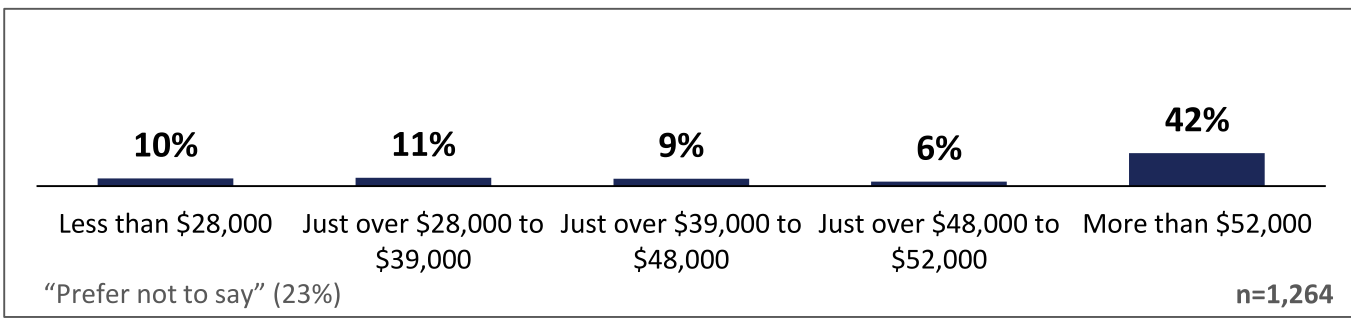
Demographic Breakdown

Residential

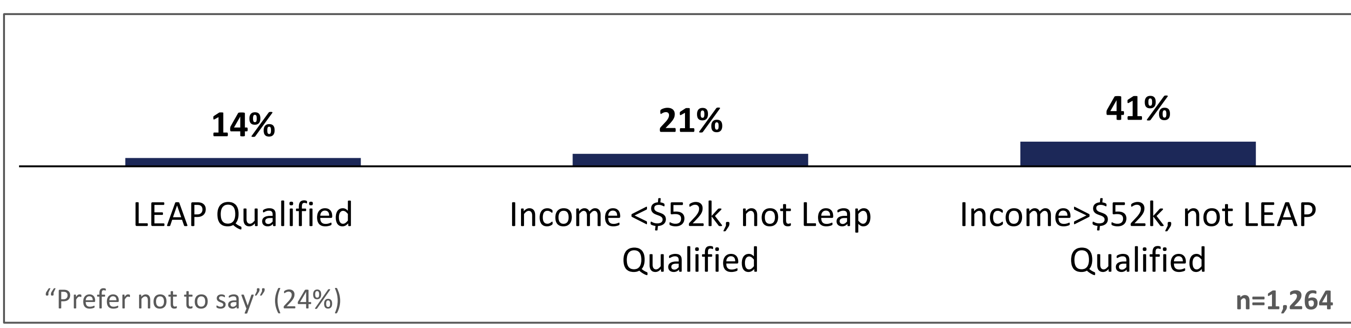
Q Household Size



Q After Tax Household Income



Q **LEAP Qualification** (calculated based on household size and income)



INNOVATIVE RESEARCH GROUP

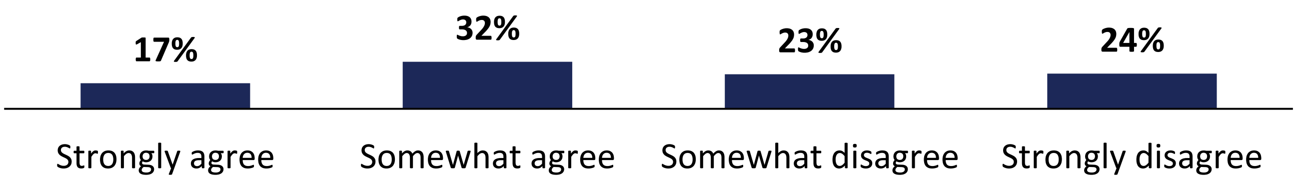
Representative Workbook

Environmental Controls

Residential

Thinking generally about the electricity system in Ontario, including generation, transmission and local distribution, do you agree or disagree with the following statements?

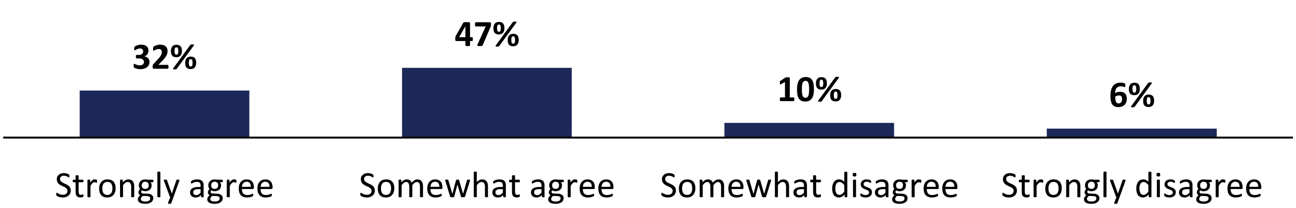
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know" (4%) not shown.

n=1,264

Q Customers are well served by the electricity system in Ontario.



"Don't know" (5%) not shown.

n=1,264

About this Consultation

Welcome to Niagara Peninsula Energy's Customer Engagement!

Niagara Peninsula Energy (NPEI) needs your input on choices that will impact the services you receive and the rates that you pay.

- **NPEI** is developing its investment plan for 2021 to 2025. This plan will determine the investments NPEI will make in equipment and infrastructure; the services it provides; and the rates you pay.
- As **NPEI** plans for the future, they want to ensure their business decisions are aligned with customers priorities, preferences, and needs.
- Throughout this survey, information will be provided in an effort to give you more background on which to base your responses.
- While responding to the following questions, remember that there are no wrong answers, and that your individual responses will remain anonymous.
- This customer engagement will take approximately 25-35 minutes to complete, depending on the level of feedback you wish to provide. Your progress will be saved as you move through the workbook, meaning you can leave and return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired NPEI to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one (1) $500 cash prize.

Representative Workbook

Background Information

Niagara Peninsula Energy Inc.
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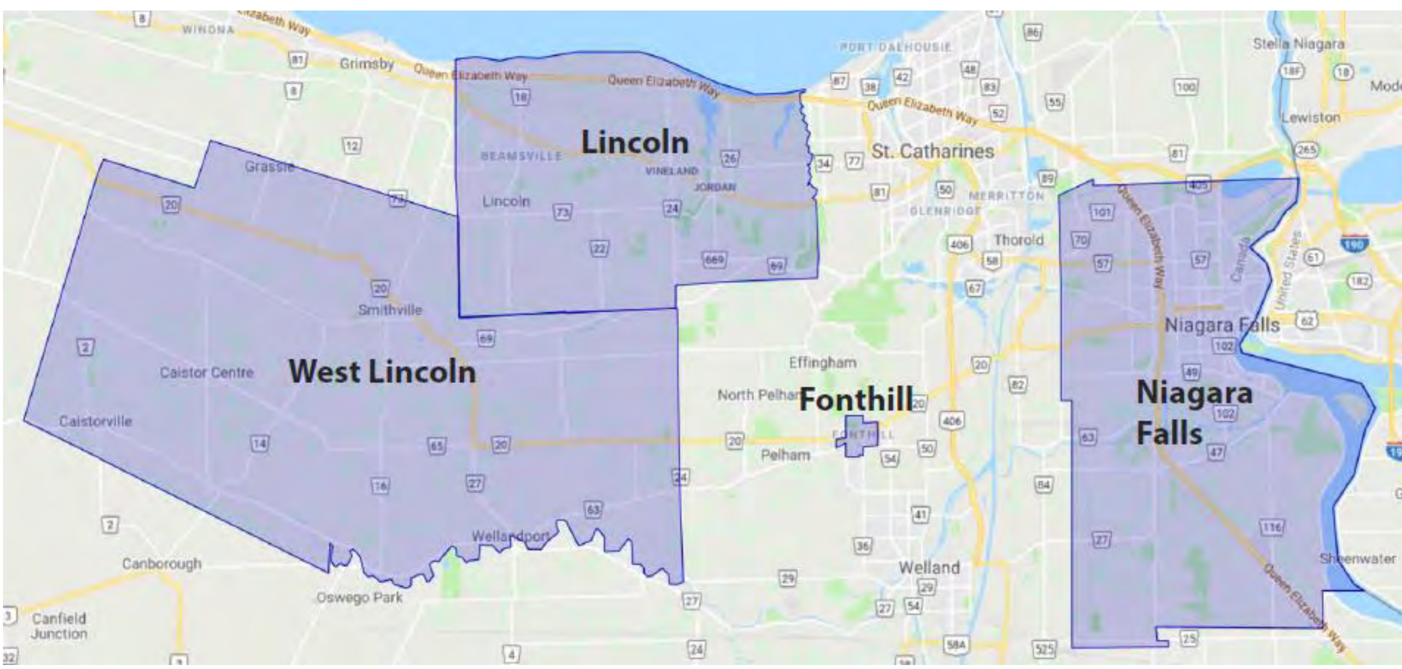
Electricity 101

Who is Niagara Peninsula Energy?

NPEI provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham, and Township of West Lincoln.

- NPEI serves an area of approximately 827 square kilometers and a customer base of approximately 55,600 residential and business customers, containing a mix of urban and rural electrical distribution.
- NPEI is jointly owned by the municipalities it services.
- NPEI manages all aspects of the electricity distribution business and is regulated by the Ontario Energy Board (OEB).
- As a local distribution company (LDC) and regulated entity, NPEI applies for, and receives approval from the regulator to charge for its services.



Representative Workbook
Background Information

Electricity 101

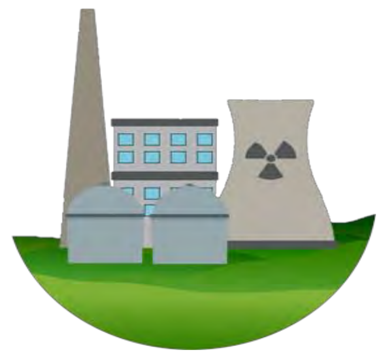
Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

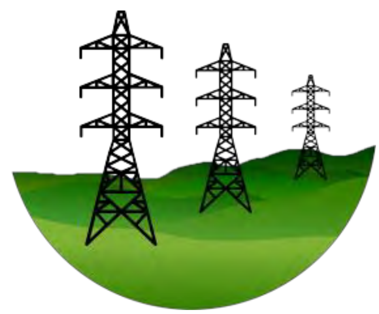
Ontario's electricity is generated using a mix of nuclear, gas-fired, and water power (hydro), as well as biomass and renewable sources such as wind and solar technology. In Ontario, a number of companies own these generating stations but approximately half of the electricity is generated by Ontario Power Generation. The Independent Electricity System Operator (IESO) balances the supply of, and demand for, electricity on a second-by-second basis and directs its flow across the high-voltage transmission lines.



Transmission

How electricity travels across Ontario

Once generated, electricity must be transported to electrical substations across the province. Due to the large amount of power and long distances, transmission normally takes place at high voltages with the lines suspended on large, steel towers. The province has more than 30,000 kilometres of 'electricity highway', most of which is owned and operated by Hydro One.



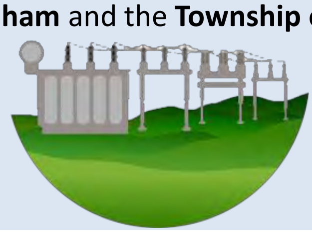
Local Distribution

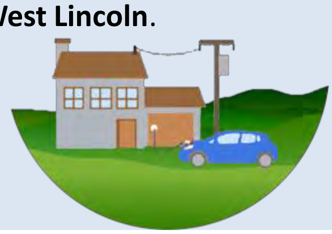
How electricity is delivered to the end-consumer

NPEI is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, NPEI delivers electricity to approximately 55,600 residential and business customers.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.





npe niagara peninsula energy Inc.
Your Local Utility

Representative Workbook

Familiarity with Ontario's electricity system

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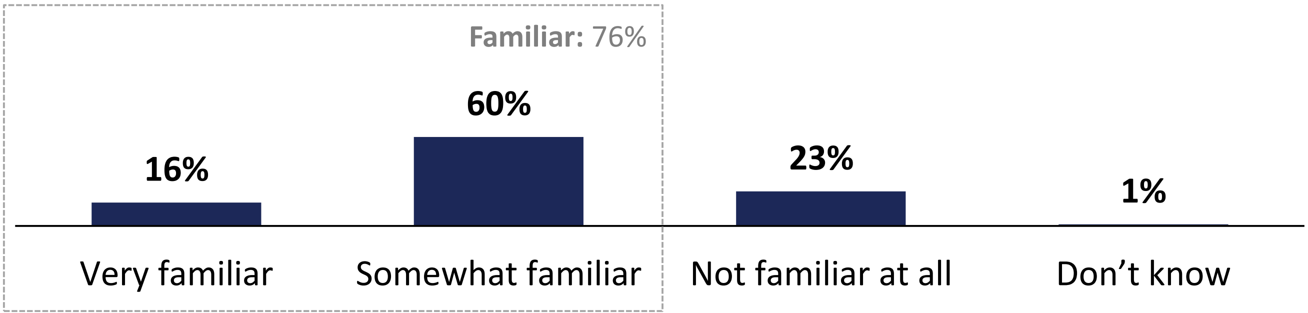
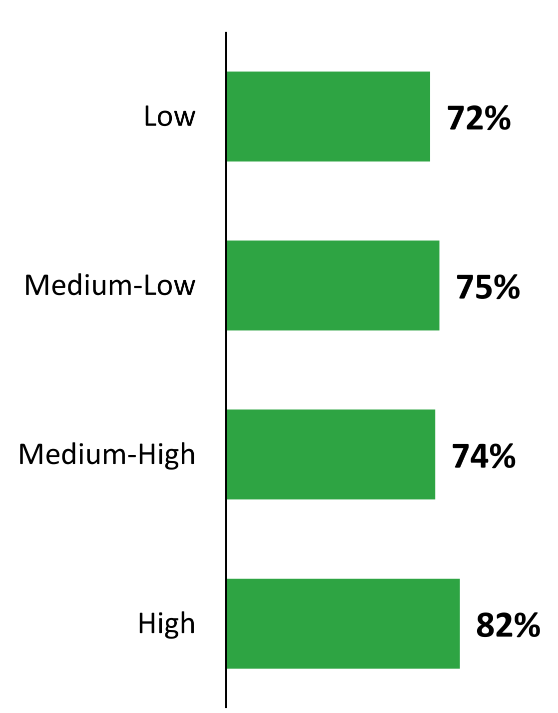
Residential

Q Before this survey, how familiar were you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?



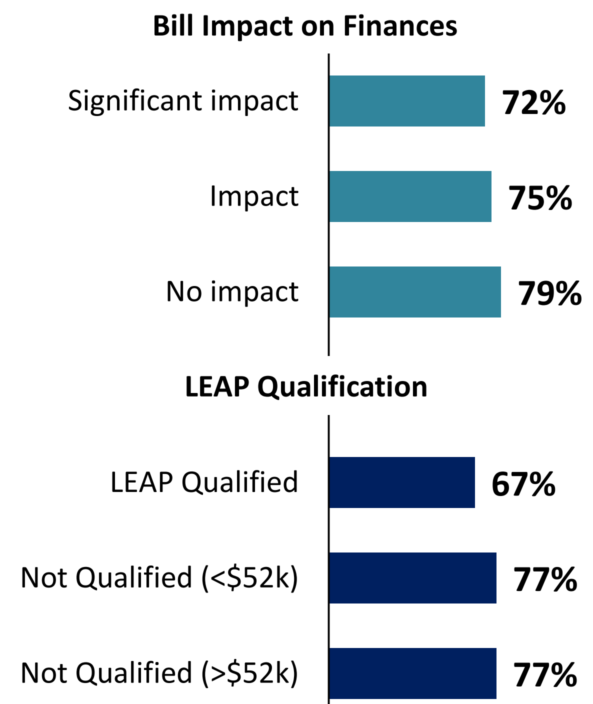
Consumption Segmentation

Respondents who say "Familiar"



Vulnerable Customer Segmentation

Respondents who say "Familiar"



Representative Workbook
Background Information

Electricity 101

How much of my electricity bill goes to Niagara Peninsula Energy?

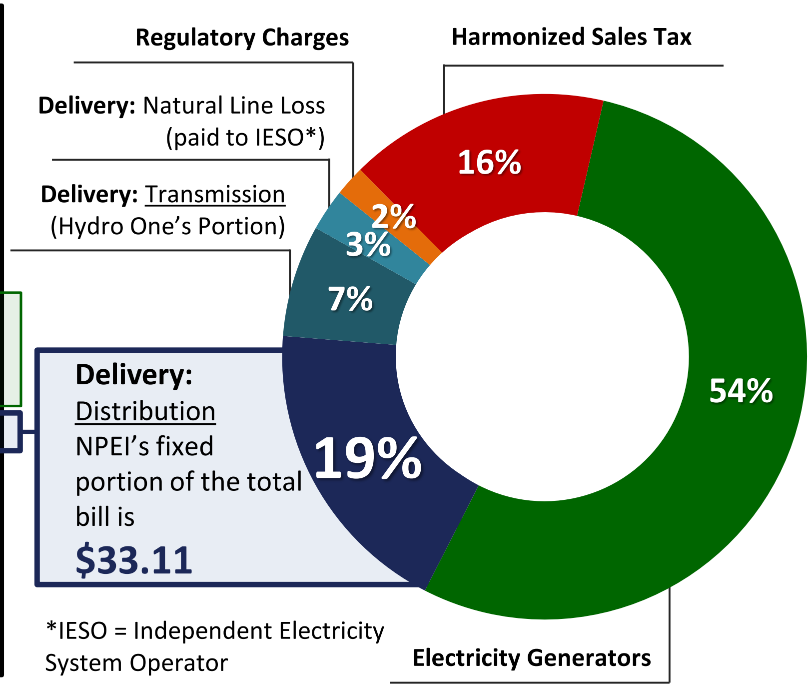
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge.
- Distribution makes up about **19%** of the typical residential customer's bill.
- For residential customers, NPEI's portion of the delivery line on the bill is fixed and does not change based on the amount of electricity you use.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

NPEI Sample Monthly Bill*
(Based on monthly usage of 700 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Off-Peak @ 10.1 ¢/kWh	45.25
Mid-Peak @ 14.4 ¢/kWh	18.14
On-Peak @ 20.8 ¢/kWh	26.21
Delivery	46.85
Regulatory Charges	3.11
Total Electricity Charges	**$139.56**
HST	18.14
Ontario Electricity Rebate*	(-**$44.38**)
Total Amount	**$113.32**



*IESO = Independent Electricity System Operator

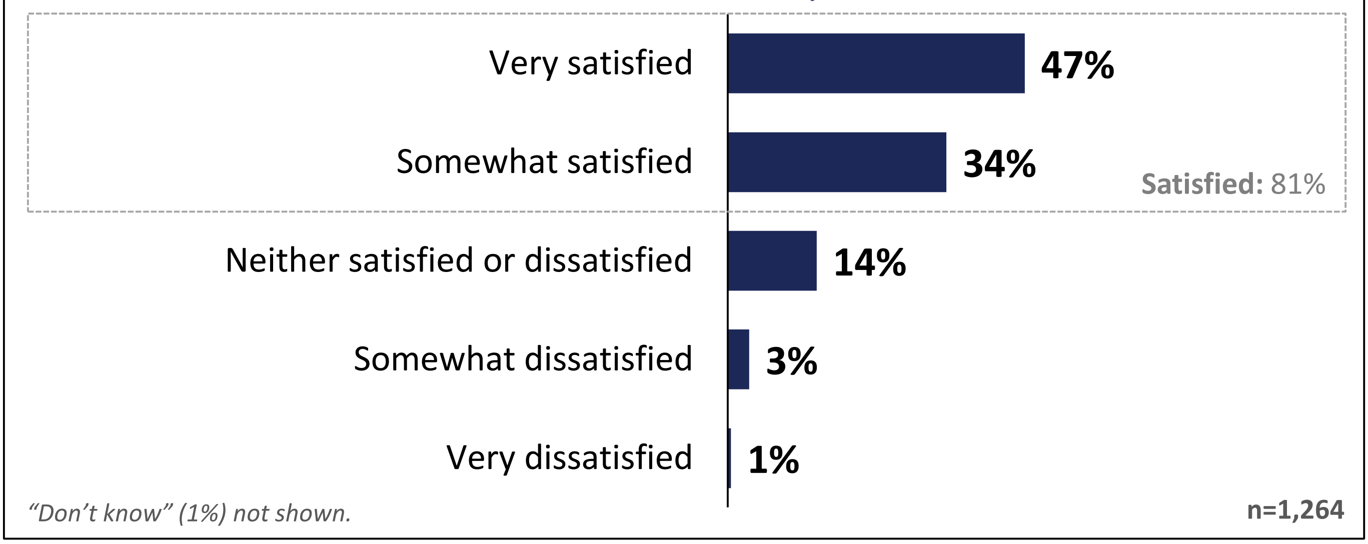
* As of November 1, 2019. Chart is based on total bill amount after applying the Ontario Electricity Rebate.

Representative Workbook

Overall Satisfaction with Niagara Peninsula Energy

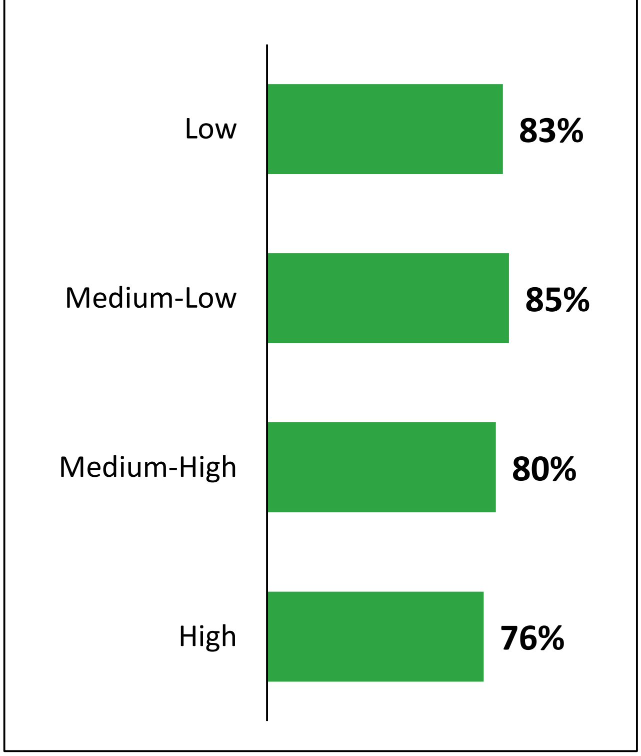
Residential

Q Thinking specifically about the services provided to you and your community by Niagara Peninsula Energy, overall, how satisfied or dissatisfied are you with the services that you receive?



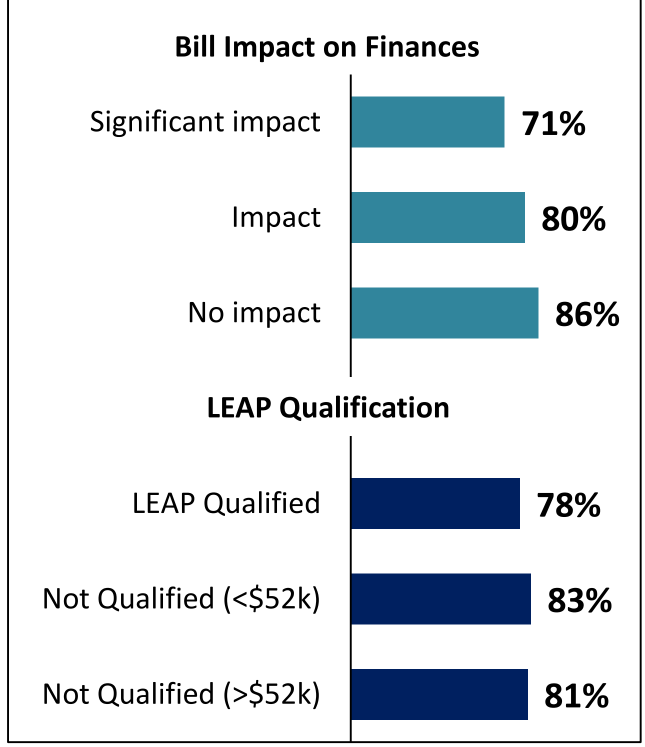
Consumption Segmentation

Respondents who say "Satisfied"



Vulnerable Customer Segmentation

Respondents who say "Satisfied"



Representative Workbook

Familiarity with Percentage if Bill Remitted to NPEI

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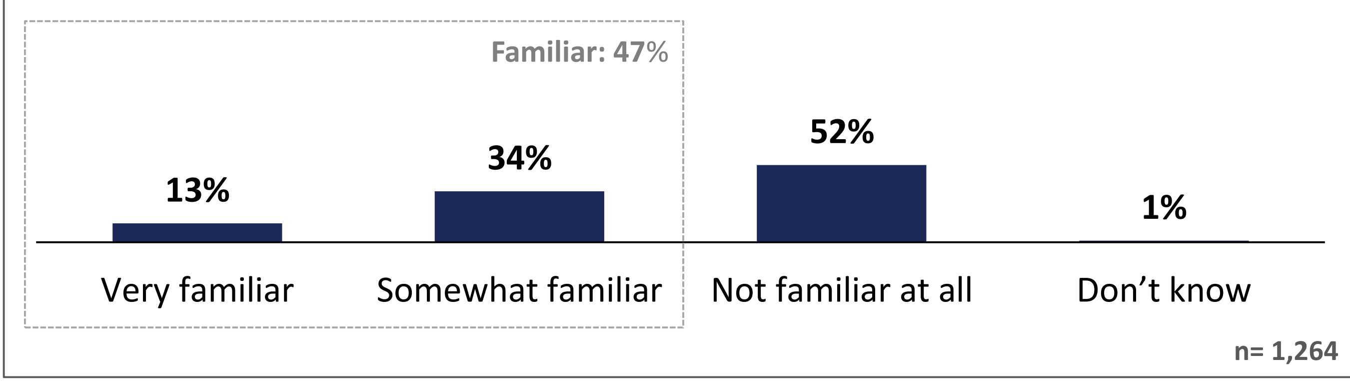
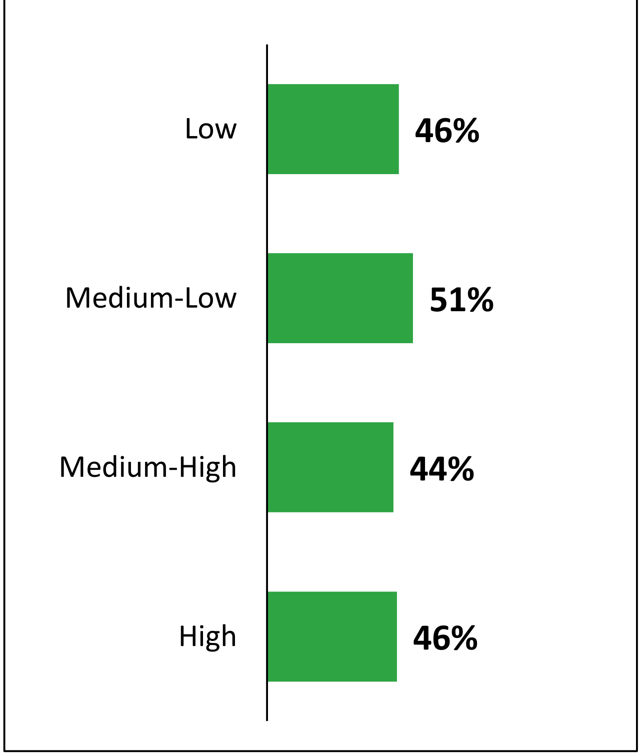
Q Before this survey, how familiar were you with the amount of your electricity bill that went to Niagara Peninsula Energy?



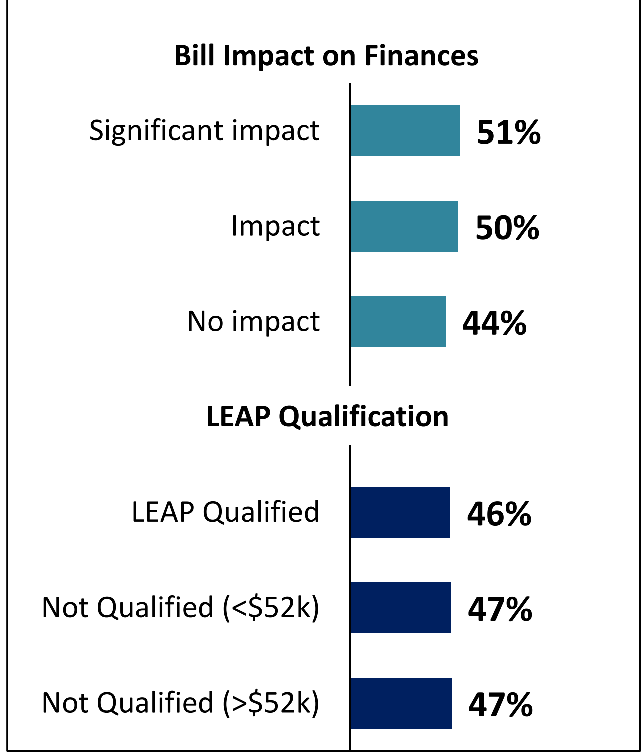
Consumption Segmentation

Respondents who say “Familiar”



Vulnerable Customer Segmentation

Respondents who say “Familiar”



Representative Workbook

How can NPEI Improve services?

Residential

Q

Is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to you?

Improving Services (n=401) 68% of respondents did not provide additional feedback	%
Improve reliability/less outages	16%
No issues/satisfied with service/keep up the good work	14%
Lower rates/Charge less	12%
Improve billing - clarity/payment terms/methods/website	6%
Invest in infrastructure/move cables underground	6%
Do not increase rates/keep rates affordable	4%
Decrease/eliminate delivery charges	4%
Provide more info on energy consumption/conservation/renewables	3%
Offer rebates/assistance for low income/seniors	3%
Modify time of use/peak rates	2%
Improve customer service/meter reading	2%
Improve outage communication	2%
Find internal efficiencies/provide info on cost cutting	2%
Maintain lines/improve tree clearing	1%
Other	1%
None	20%
Don't Know	2%

Niagara Peninsula Energy Background

Building Niagara Peninsula Energy's draft plan

NPEI has put together its draft business plan based on the information and input from various sources, such as:

- **Legal and regulatory** requirements by continuing to meet its obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected through both ongoing dialogues and specific engagements, such as this.

There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their businesses and serve their customers.

- **Policy**: The Ontario Ministry of Energy, Northern Development and Mines (MNDM) creates energy policy for the province.
- **Regulation**: The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.
- **Operations and Planning**: The Independent Electricity System Operator (IESO) manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

Ontario ENERGY /ÉNERGIE

ONTARIO ENERGY BOARD

ieso Connecting Today. Powering Tomorrow.

Niagara Peninsula Energy Background

How did customer feedback shape Niagara Peninsula Energy's draft plan?

NPEI is placing more emphasis on incorporating customer feedback into the planning process than ever before.

NPEI engages with its customers both in day-to-day interactions and in a variety of customer engagement activities. These interactions help identify customer needs and preferences, and inform how the utility plans for the future.

This past summer, NPEI engaged with **thousands of residential and business customers** from across its service territory – both in person and through telephone and online surveys.

What did NPEI hear from customers like yourself?

1. The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates".

2. Among competing outcomes, **price**, **reliability**, and **finding internal cost efficiencies** are the top three priorities for both residential and small business customers.

3. While keeping price at a reasonable and affordable level is an important priority, many customers feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Considering this feedback, as well as the information and inputs discussed on the previous page, NPEI has developed a draft plan that is responsive to:

1. Legal requirements by continuing to meet its obligations, including safety and reliability;

2. A transformer station upgrade to accommodate the new Niagara South Hospital and future surrounding growth.

3. Mandatory service connections to accommodate new customers and customer-required upgrades, of which NPEI does not have control over how and when these costs are incurred.

4. Customer feedback by:

    a) Keeping distribution price increases as low as possible;

    b) Maintaining long-term performance for customers experiencing average or better service;

    c) Improving service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,

    d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

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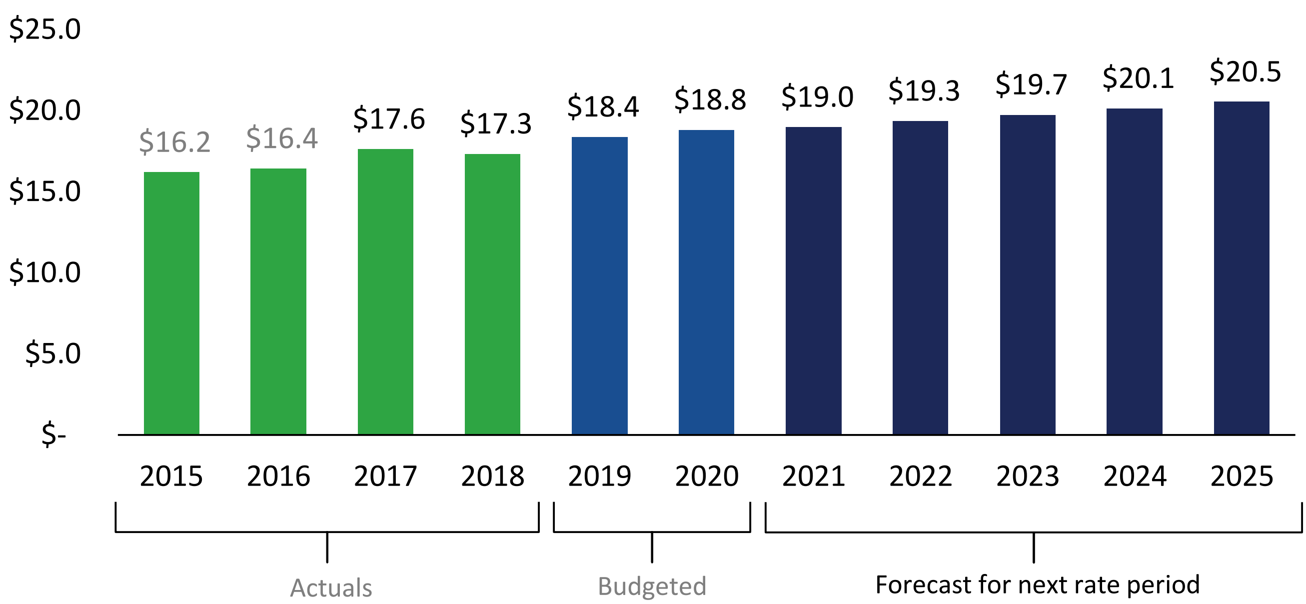
Niagara Peninsula Energy Background

Operating Expenses

In this section, we want to focus on operating expenses and how NPEI compares to its peers.

NPEI's operating budget covers recurring expenses, such as the maintenance of poles, wires, transformers, fleet and buildings as well as proactive maintenance programs such as tree trimming, and payroll for employees. Meter reading, postage, cyber security and hardware/software maintenance expenses are billing and customer service-related expenses. The proposed 5-year plan, between 2021 and 2025, would see NPEI spend an estimated total of $98.7 million on operations.

NPEI's Current and Forecasted Operating Expenses, per Year (Millions)*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

Representative Workbook
Background Information

NPEI's **operating costs** are benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, NPEI's operating costs per customer was **$311.67**, which is slightly more than some, while less than both Hydro One and Canadian Niagara Power.

2018 Operating & Maintenance and Administration (OM&A) Per Customer ($)

The diverse geographical nature of NPEI's service territory, which is a mix of urban and rural communities is a large consideration/driver of these OM&A costs. In some parts of the service territory, there may be less than 30 customers per kilometer of line. Despite low density, these lines still require the same level of ongoing maintenance, including tree trimming and other expenses that contribute to operating the system; thereby resulting in a higher cost per customer.

Niagara Peninsula Energy Background

Operating Expenses

Recall, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge NPEI's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found at oeb.ca/participate.

This customer engagement however, is focused on capital investments.

Detailed discussion of NPEI's operating budget is left to experts from the OEB and intervenors in the formal rate application review; this workbook focuses on collecting your view on competing trade-offs in capital investments.

Representative Workbook

Approach to Operating Expenses

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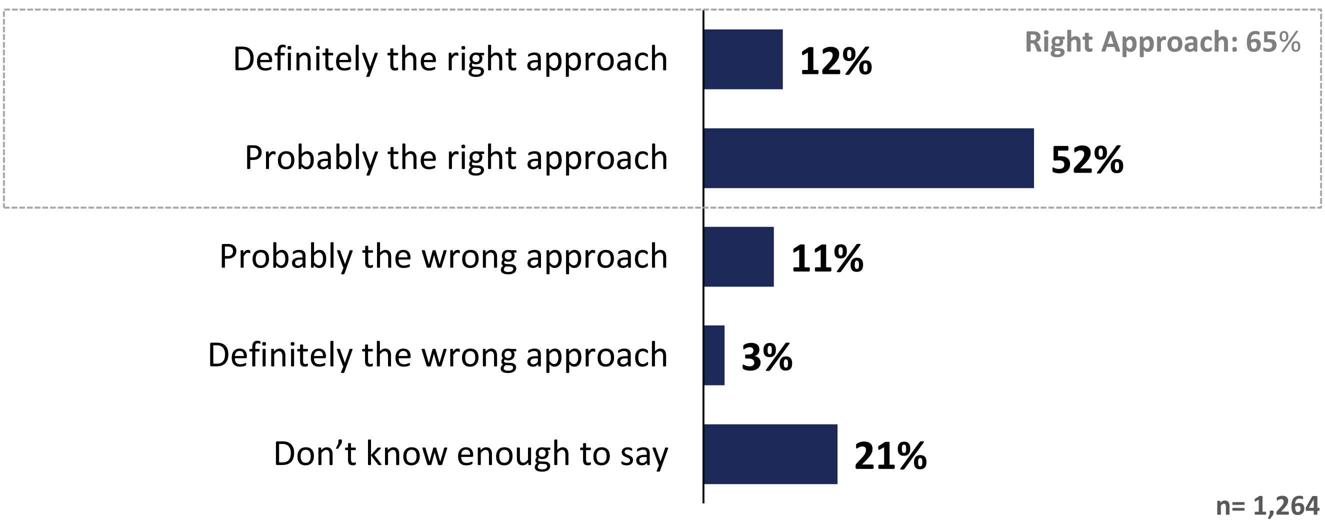
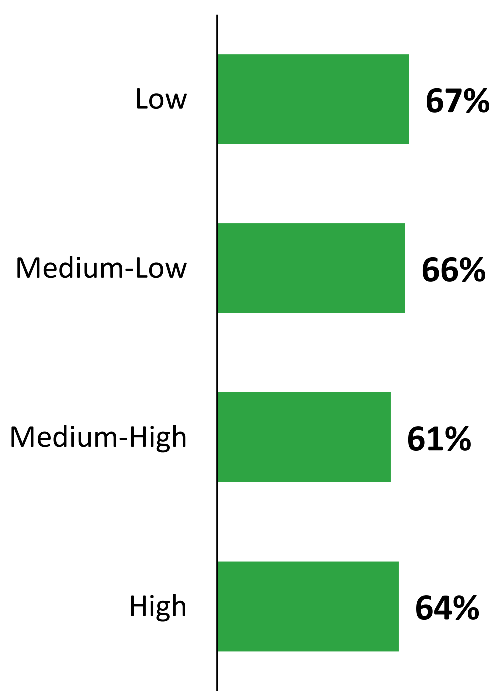
Residential

Q Does leaving the detailed discussion about Niagara Peninsula Energy's operating budget to experts from the OEB and intervenors seem like the right approach or wrong approach to you?



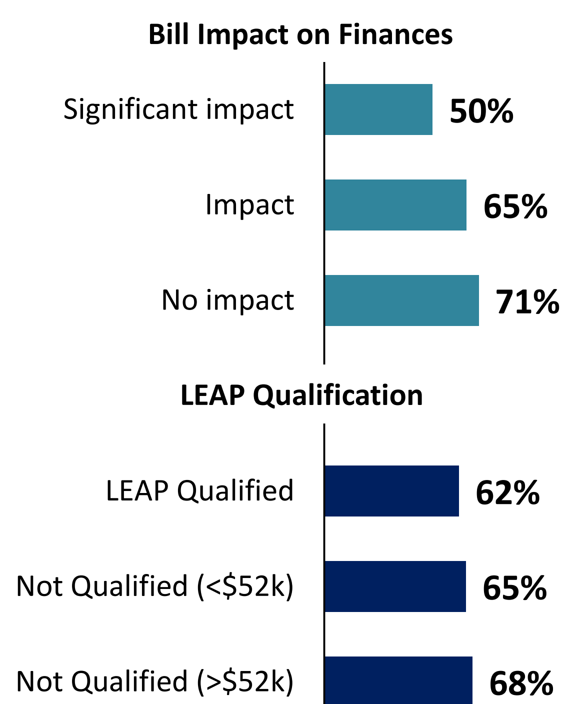
Consumption Segmentation

Respondents who say "Right Approach"



Vulnerable Customer Segmentation

Respondents who say "Right Approach"



Representative Workbook

Background Information

Niagara Peninsula Energy Background

Capital Investments

NPEI's **capital budget** covers items that, once purchased, have lasting benefits over many years. Year-over-year, regardless of external drivers, NPEI will need to make investments in the core distribution system, including poles, wires, cables and transformers.

Based on initial customer input and the approach outlined previously, NPEI believes the capital expenditure required to address system renewal, maintain system reliability and safety, and invest in other infrastructure priorities between 2021 and 2025 is estimated to be **$70.3 million**.

NPEI classifies the costs of four types of capital investment between 2021 and 2025. Each of these four investment categories helps NPEI pace and prioritize projects.

2021-2025 Forecasted Capital Investments

System Renewal ($38.2 million)

These projects are a mix of planned end-of-life replacements and emergency replacements.

Projects Include: Replacement of existing overhead wires, poles, and pole mounted transformers, underground cables and transformers and transformer station upgrades.

System Access ($17.1 million)

"Must do" investments that respond to customer requests for new connections or new infrastructure development.

Projects Include: NPEI's share of new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs.

General Plant ($8.4 million)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

Projects Include: Financial and customer IT systems, enhanced cyber security investments, facility renovations, backup generation, and vehicle replacements.

System Service ($6.6 million)

These investments consist of projects that address capacity constraints, improve system reliability and customer service.

Projects Include: Installation of automated switches and system expansion to supply new development.

Representative Workbook

Background Information

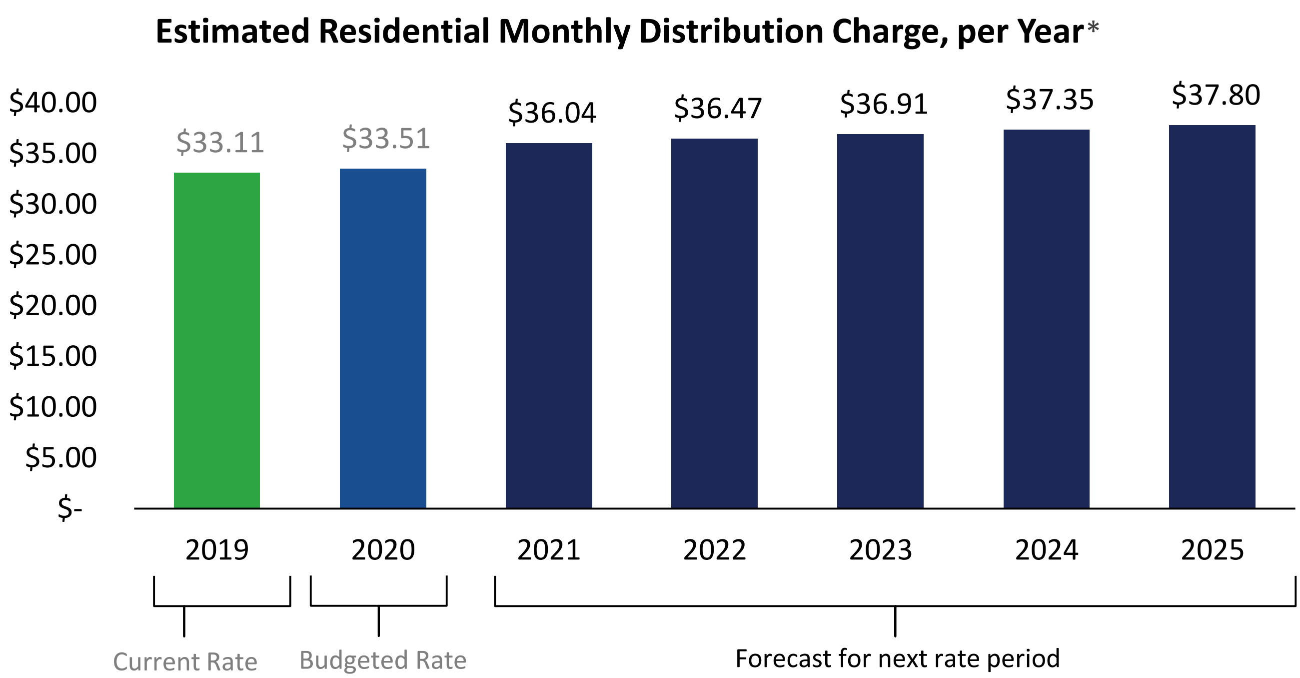
Niagara Peninsula Energy Background

How much will this draft plan cost me?

Remember, the current typical NPEI residential customer's electricity bill is about $113 per month, of which $33.11 goes to NPEI.

It is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $2.53 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by $4.29.
- As a result, the distribution charges on the typical residential customer's monthly bill would increase from $33.51 in 2020 to $37.80 by 2025.



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI is looking for your input on its preliminary plan to ensure it is making the spending decisions that matter to you, the customer.

The following sections of this workbook will explore some of the choices Niagara Peninsula Energy needs to make to help finalize its preliminary plan.

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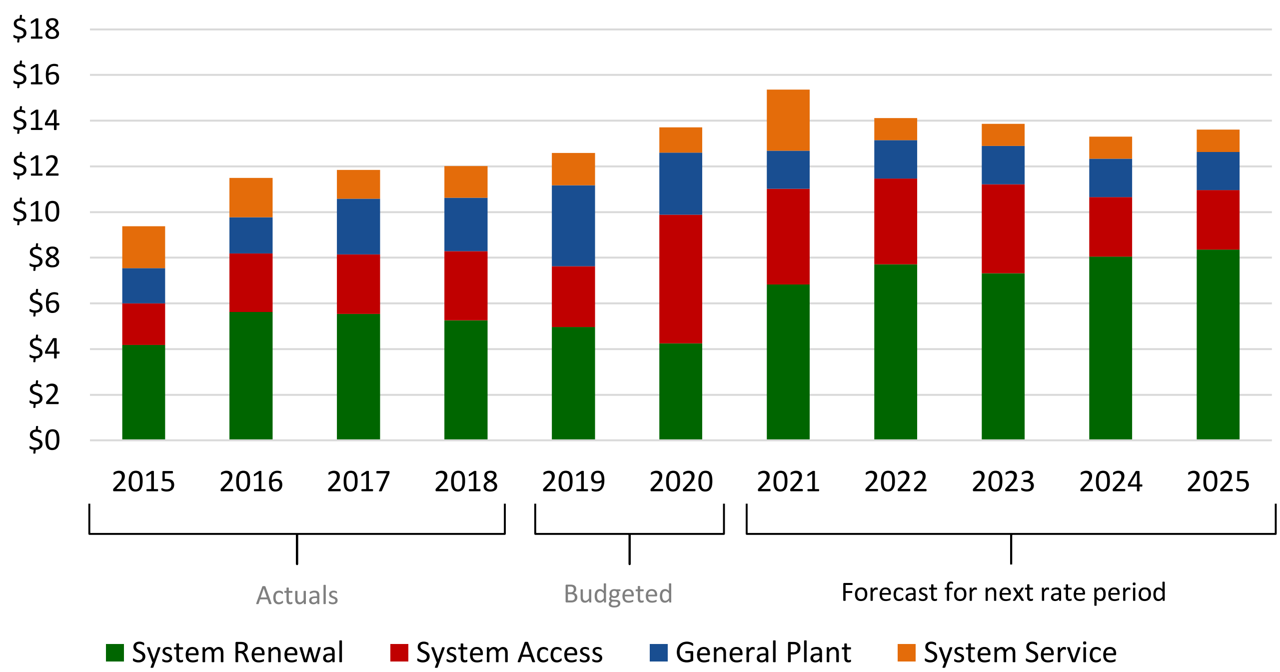
Niagara Peninsula Energy Background

Pacing Capital Investments

The overall amount NPEI invests in capital projects remains generally the same year over year, but what does change is where these investments are made. In some years, when unplanned or unforeseen investments are needed, NPEI will re-allocate funds to make room for these projects within the approved budget. This helps limit the overall amount that the distribution charges fluctuate year-over-year.

The chart below outlines NPEI's spending in past years, and proposed spending for the 5-year period 2021 to 2025.

2015 – 2025 Historical and Forecasted Capital Investments*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

System Access expenditures are budgeted to increase to $5.6M in 2020 to accommodate a number of large commercial customer growth projects as well as municipal road work.

Representative Workbook

Approach to Pacing Investments

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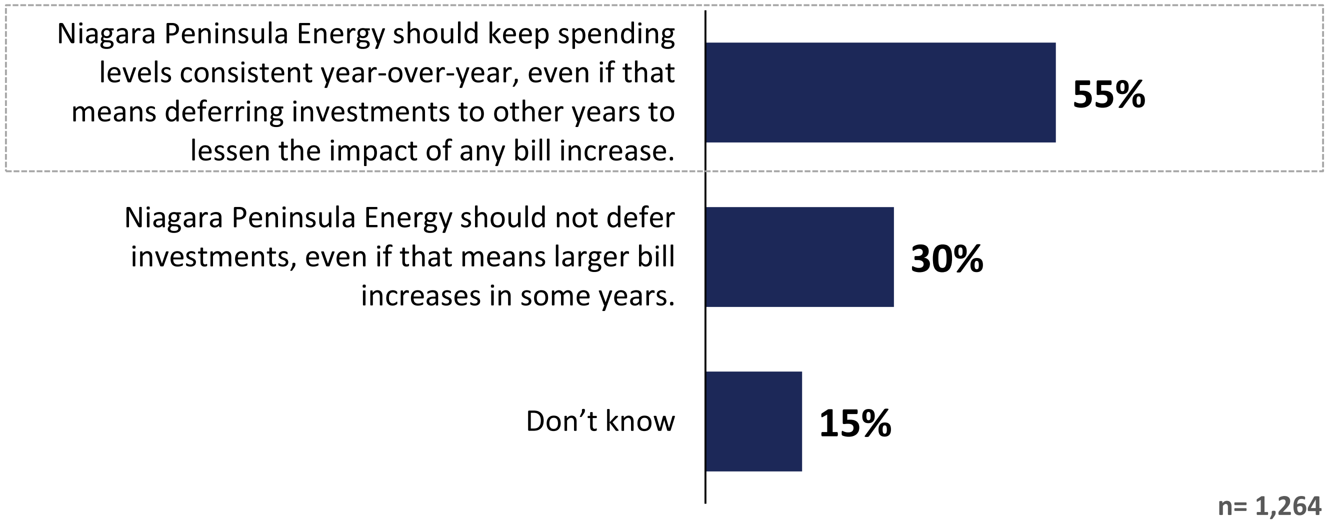
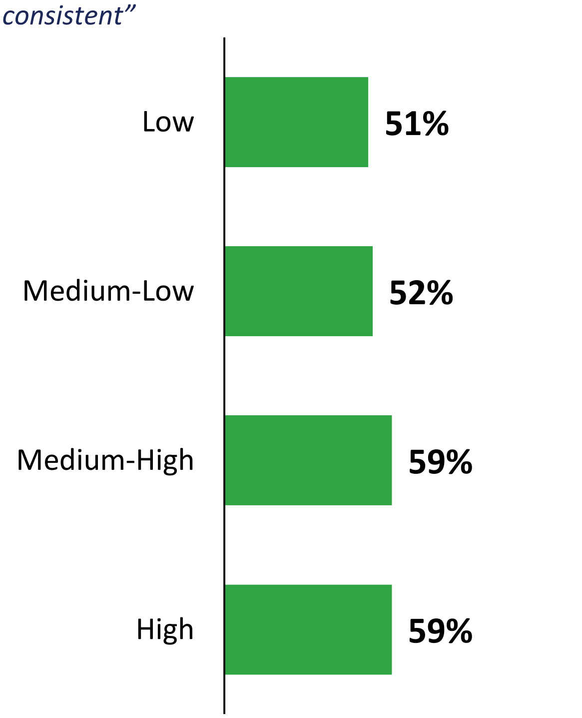
Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to pacing investments?

niagara peninsula energy inc. *Your Local Utility*



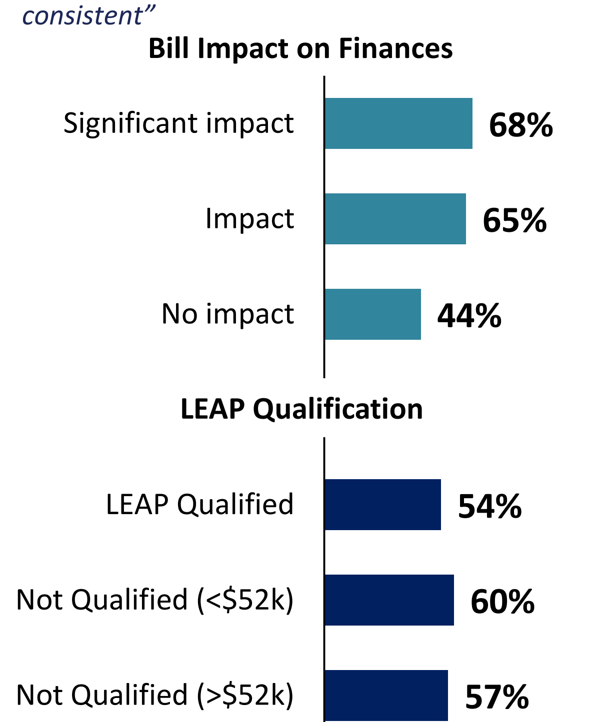
Consumption Segmentation

Respondents who say "Keep spending consistent"



Vulnerable Customer Segmentation

Respondents who say "Keep spending consistent"



Representative Workbook

Residential

Additional Feedback: Approach to Pacing Investments

Q Additional Feedback (Optional)

Additional Feedback (n=163) 87% of respondents did not provide additional feedback	**%**
Rate increases should at a reasonable stable rate/ small increases over time when necessary	23%
Deferring only increases future prices/invest now in technology and equipment	23%
No increase-keep cost low too high already	17%
Cost should be incurred by/Builders/developers/Government	13%
Find efficiencies/cost savings/use profits/capital investments	6%
Case by case basis/Prioritize spending on what is needed most	4%
Reliability of services is paramount	2%
Other	9%
None	3%
Don't know	1%

INNOVATIVE RESEARCH GROUP

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Niagara Peninsula Energy Background

Mandatory Investments

Federal, provincial, and municipal governments as well as regulators set requirements and standards that NPEI must satisfy. Mandatory investments can be broken down into three categories:

- **Connecting customers**: This includes connecting customers to the grid when a new home or building is constructed or modified.
- **Moving equipment**: This includes moving equipment like poles and cables for road widening.
- **Mandated obligations**: This includes installing and maintaining customer meters and transferring electricity from the provincial transmission system.

These mandatory investments mean that about **one-in-four dollars (23%)** of your distribution rates over the past five years have not been available for other non-mandatory investments. Looking forward to the 2021-2025 period, NPEI forecasts a similar level of mandatory investments, driven largely by:

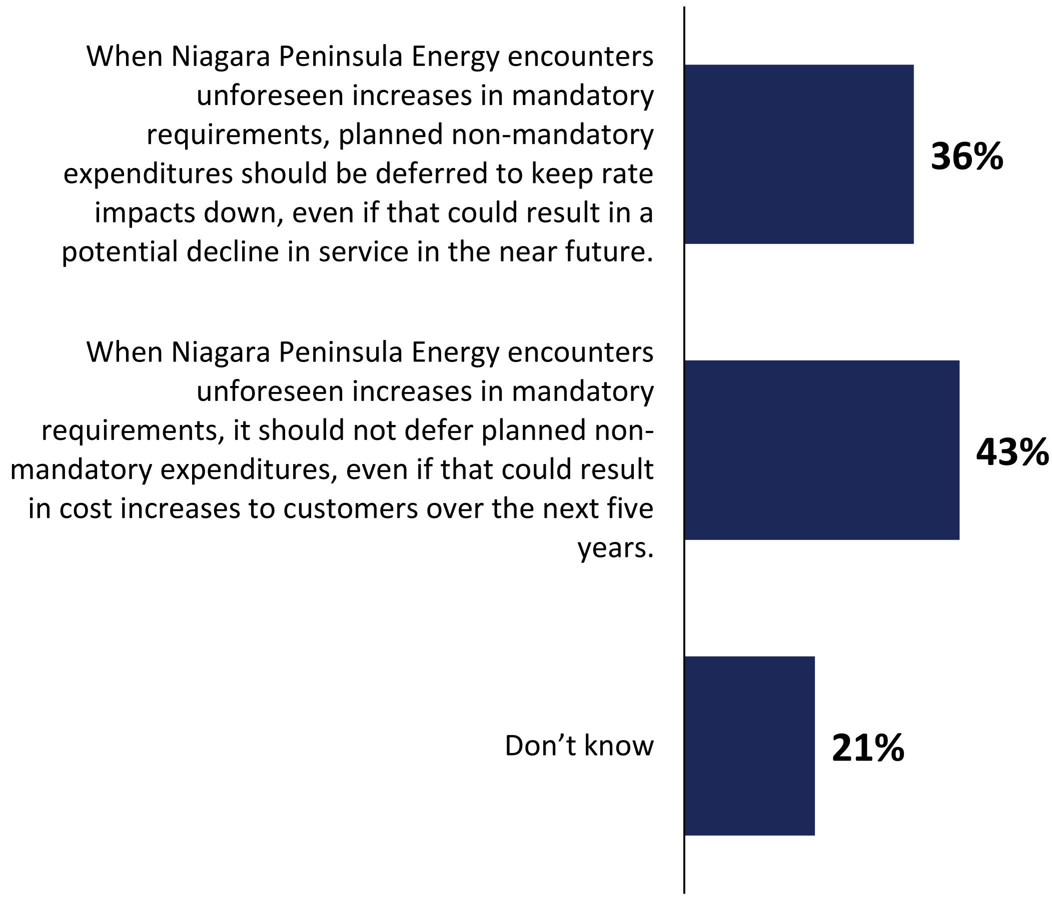
- **Preparing to connect the new Niagara South hospital;**
- **Work to accommodate the 2021 Canada Summer Games in the Niagara Region, and;**
- **Work to accommodate growth and future electricity capacity needs.**

Representative Workbook

Approach to Mandatory Investments

Residential

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to mandatory and non-mandatory spending?



n= 1,264

INNOVATIVE RESEARCH GROUP

Representative Workbook

Residential

Additional Feedback: Approach to Mandatory Investments

Q Additional Feedback (Optional)

Additional Feedback (n=154) 88% of respondents did not provide additional feedback	**%**
Case-by-case basis/New developers/builders/Company/2021 Canada Games/Government-should fund costs	31%
Increase within reason when expenditures are necessary/Balance over 5 years	23%
Unforeseen increases should not be encountered / impact services -Plan better/should already be in budget	22%
Keep rates low/Cost is already to high-no increase	8%
When issues are resolved rates should be decreased	4%
Cut back on salaries/operating costs	1%
Other	10%
None	1%

INNOVATIVE RESEARCH GROUP

Making Choices (1 of 7)

Overhead Pole Replacement

A recent asset health condition assessment shows that **575 or approximately 3%** of the poles in NPEI's distribution system are in *poor* or *very poor* condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a car accident.

On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period.

NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

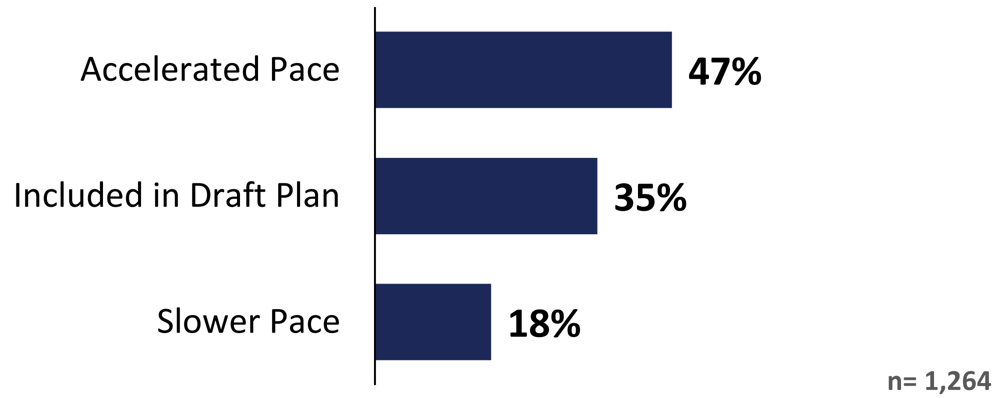
Option	Poles Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	1,000 by 2025 (200 per year)	Address the very poor and some of the poor condition poles identified in the Asset Condition Assessment.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	500 by 2025 (100 per year)	Address most of the very poor condition poles identified in the Asset Condition Assessment and annual pole inspections by 2025.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	250 by 2025 (50 per year)	Address only the poles in need of immediate replacement, as identified in the annual pole inspection report.

Representative Workbook

Overhead Pole Replacement

Residential

Q Which of the following options do you prefer?



Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Accelerated Pace	47%	42%	51%
Included in Draft Plan	34%	42%	31%
Slower Pace	19%	16%	18%

Bill Impact on Finances	Significant impact	Impact	No Impact
Accelerated Pace	32%	44%	55%
Included in Draft Plan	25%	38%	36%
Slower Pace	43%	17%	9%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Accelerated Pace	37%	41%	53%
Included in Draft Plan	30%	38%	36%
Slower Pace	33%	22%	11%

Representative Workbook

Additional Feedback: Overhead Pole Replacement

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Q Additional Feedback (Optional)

Additional Feedback (n=138) 89% of respondents did not provide additional feedback	**%**
Bury lines/better to replace with underground lines	21%
Be proactive/pay now to save later/costs will only increase	20%
Reliability/safety outweighs cost	13%
Investigate/Invest in new pole technology	6%
Replace within budget/no increase to consumer	6%
Information misleading/skeptical about figures/inspection criteria	6%
Replace as necessary/most urgent first/my street first	5%
Issue due to poor management/maintenance should have been ongoing	4%
New developments/drivers involved in accidents should be responsible	3%
Extreme weather events should make this a priority	3%
Cost acceptable	2%
Need more information	1%
Coordinate with other services/find other revenue streams	1%
Other	2%
None	5%
Don’t know	1%

Making Choices (2 of 7)

Overhead transformer replacement

Transformers are a critical piece of distribution equipment that reduce voltage from the higher levels that are more efficient to move electricity long distances to lower levels that are safer to connect to homes and businesses. They are typically either located on the ground, in underground vaults, or attached to distribution poles

A recent asset health condition assessment shows that **1,251 or approximately 21%** of the overhead transformers in NPEI's distribution system are in poor or very poor condition.

Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances.

However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses.

NPEI is proposing a new program to proactively replace **250 of the 677 or 37%** of the overhead transformers identified as very poor condition before they fail over the course of the next five years.

As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

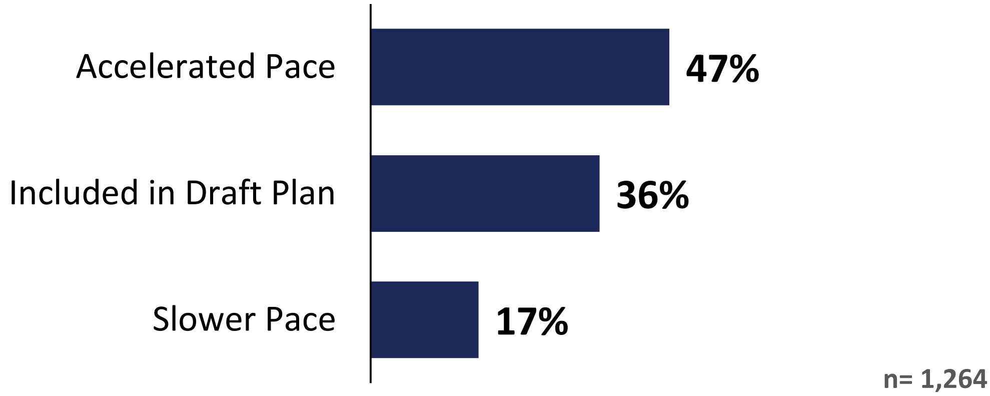
Option	Transformers Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	375 by 2025 (75 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	250 by 2025 (50 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	125 by 2025 (25 per year)	Address only the worst of the polemount transformers identified as very poor in the Asset Condition Assessment report.

Representative Workbook

Overhead transformer replacement

Residential

Q Which of the following options do you prefer?



Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Accelerated Pace	47%	47%	46%
Included in Draft Plan	34%	40%	40%
Slower Pace	19%	13%	14%

Bill Impact on Finances	Significant impact	Impact	No Impact
Accelerated Pace	31%	42%	57%
Included in Draft Plan	30%	40%	35%
Slower Pace	38%	18%	8%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Accelerated Pace	38%	41%	53%
Included in Draft Plan	31%	40%	37%
Slower Pace	31%	19%	11%

Representative Workbook

Residential

Additional Feedback: Overhead transformer replacement

Q Additional Feedback (Optional)

Additional Feedback (n=99) 92% of respondents did not provide additional feedback	**%**
Replace with underground/more secure alternative	20%
Reliability/safety outweighs cost	13%
Be proactive/pay now to save later/costs will only increase	8%
Replace as necessary/most urgent/poor transformers first	8%
Issue due to poor management/maintenance should have been ongoing	7%
Replace within budget/find efficiencies/no increase to the consumer	6%
Need more information	4%
Data/figures questionable	3%
Cost acceptable/negligible	3%
Keeping consumer costs low should be a priority/cost already high	2%
Outages acceptable	2%
Only affected customers should pay	1%
Coordinate with pole replacement	1%
Other	1%
None	18%
Don't Know	1%

Making Choices (3 of 7)

Converting Outdated Underground Kiosk Transformers

NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program has been pushed off, and today, there remains 75 transformers in need of replacement.

NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.

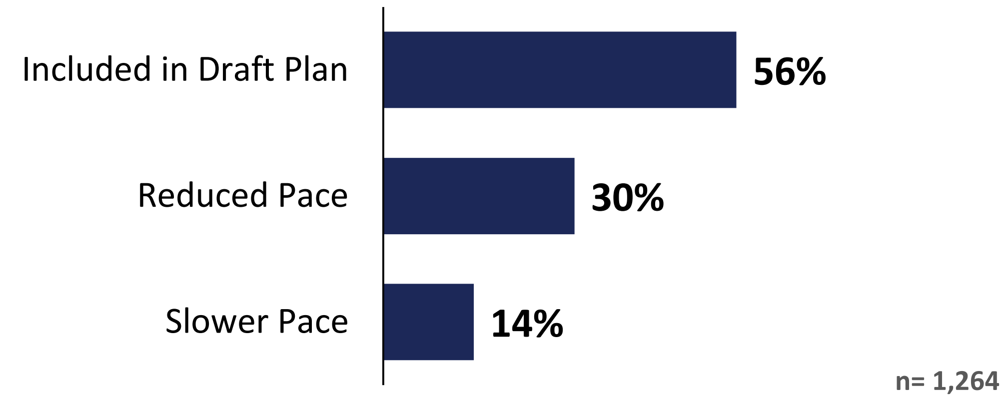
Option	Transformers Installed	Expected Outcome
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	55 by 2025 (11 per year)	Work towards eliminating all old installations over the next 7 years.
Reduced Pace ***Decrease*** *of $0.02 per month annually ($0.24 less per year)*	25 by 2025 (5 per year)	Work towards eliminating all old installations over the next 15 years.
Slower Pace ***Decrease*** *of $0.03 per month annually ($0.36 less per year)*	10 by 2025 (2 per year)	Work towards eliminating all old installations over the next 35 years.

Representative Workbook

Converting Outdated Underground Kiosk Transformers

Residential

Q Which of the following options do you prefer?



Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Included in Draft Plan	55%	61%	49%
Reduced Pace	29%	29%	37%
Slower Pace	15%	10%	15%

Bill Impact on Finances	Significant impact	Impact	No Impact
Included in Draft Plan	27%	53%	69%
Reduced Pace	37%	33%	25%
Slower Pace	36%	14%	6%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Included in Draft Plan	42%	52%	63%
Reduced Pace	35%	32%	27%
Slower Pace	24%	16%	10%

Representative Workbook

Residential

Additional Feedback: Underground Kiosk Transformers

Q Additional Feedback (Optional)

Additional Feedback (n=75) 94% of respondents did not provide additional feedback	**%**
Reliability/safety outweighs cost	22%
Replace as necessary/most urgent/outdated first/run to fail	13%
Be proactive	9%
Need more information	8%
Replace within budget/find efficiencies/no increase to the consumer	7%
Issue due to poor management/maintenance should have been ongoing	6%
Only affected customers should pay	5%
Improve infrastructure	4%
Other	4%
None	17%
Don't Know	6%

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Making Choices (4 of 7)

Underground cable replacement

Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years.

Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses.

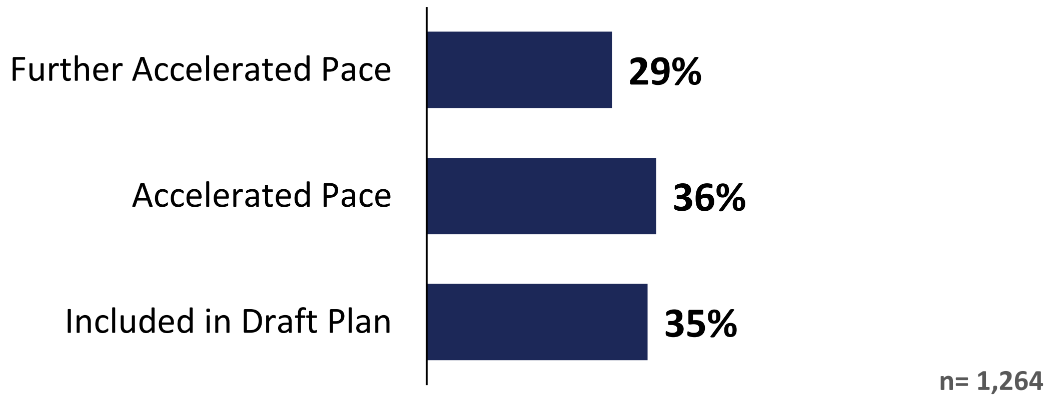
Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.

Option	Km of cable installed	Expected Outcome
Further Accelerated Pace ***Additional*** *$0.13 per month annually ($1.56 more per year)*	24 km by 2025 (4.8 km per year)	Proactively replace more of the cables identified as past end of life in the Asset Condition Assessment Report.
Accelerated Pace ***Additional*** *$0.06 per month annually ($0.72 more per year)*	12 km by 2025 (2.4 km per year)	Proactively replace some of the cables identified as past end of life in the Asset Condition Assessment Report.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	2 km by 2025 (0.4 km per year)	Replace cables past end of life as other work is being completed on associated switchgear or riser poles.

Representative Workbook

Underground cable replacement

Q Which of the following options do you prefer?



Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Further Accelerated Pace	31%	27%	23%
Accelerated Pace	37%	37%	30%
Included in Draft Plan	32%	36%	47%

Bill Impact on Finances	Significant impact	Impact	No Impact
Further Accelerated Pace	27%	24%	34%
Accelerated Pace	31%	39%	37%
Included in Draft Plan	43%	37%	29%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Further Accelerated Pace	34%	23%	32%
Accelerated Pace	32%	40%	36%
Included in Draft Plan	34%	37%	32%

Representative Workbook

Residential

Additional Feedback: Underground cable replacement

Q Additional Feedback (Optional)

Additional Feedback (n=69) 95% of respondents did not provide additional feedback	**%**
Be proactive/pay now to save later/costs will only increase	13%
Invest in new cable technology/extend cable life	11%
Reliability/safety outweighs cost	11%
Issue due to poor management/maintenance should have been ongoing	10%
Need more information	8%
Replace as necessary/most urgent first	8%
Improve cable assessments/more investigation required	7%
Coordinate with other services	5%
Bury lines/better to replace with underground lines	4%
Replace within budget/no increase to consumer/cash grab	4%
Only affected customers should pay	3%
Other	1%
None	11%
Don't Know	3%

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Making Choices (5 of 7)

Subdivision underground rehabilitation

71 of the subdivisions in NPEI's service territory were constructed with **direct buried cable** which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier.

While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life.

In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs.

In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed.

Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time.

Between 2021 and 2025, NPEI is proposing a new program that will proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.

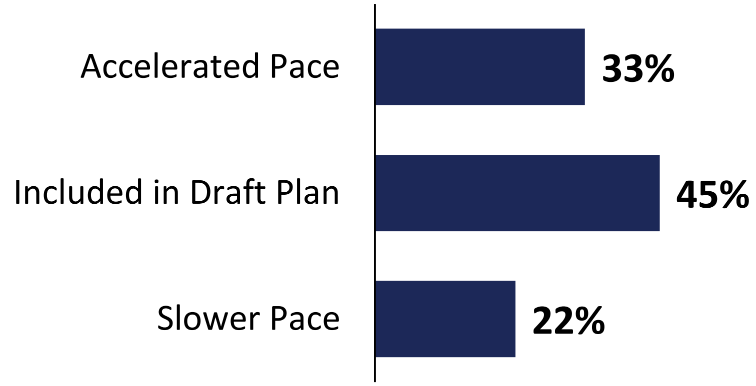
Option	Km of vault installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.02 per month annually ($0.24 more per year)*	30 km by 2025 (6 km per year)	Install 6 km of ducts or approximately four subdivisions per year.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	15 km by 2025 (3 km per year)	Install 3 km of ducts or approximately two subdivisions per year.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	7.5 km by 2025 (1.5 km per year)	Install 1.5 km of ducts or approximately one subdivision per year.

Representative Workbook

Subdivision underground rehabilitation

Residential

Q Which of the following options do you prefer?



n= 1,264

Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Accelerated Pace	35%	30%	23%
Included in Draft Plan	42%	53%	49%
Slower Pace	23%	18%	27%

Bill Impact on Finances	Significant impact	Impact	No Impact
Accelerated Pace	23%	32%	39%
Included in Draft Plan	33%	47%	47%
Slower Pace	45%	20%	14%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Accelerated Pace	34%	29%	39%
Included in Draft Plan	33%	46%	44%
Slower Pace	33%	25%	17%

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Residential

Additional Feedback: Subdivision underground rehabilitation

Q Additional Feedback (Optional)

Additional Feedback (n=54) 96% of respondents did not provide additional feedback	**%**
Charge new developments/Only affected customers should pay	19%
Need more information	13%
Slower pace/investigate in new cable technology/improvements	11%
Replace as necessary/most urgent first	9%
Be proactive/pay now to save later/costs will only increase	9%
Reliability/safety outweighs cost	8%
Issue due to poor management/maintenance should have been ongoing	7%
Information misleading/skeptical about figures/inspection criteria	5%
Bury lines/better to replace with underground lines	5%
Replace within budget/no increase to consumer	2%
None	11%

INNOVATIVE RESEARCH GROUP

Representative Workbook
Background Information

Making Choices (6 of 7)

Overhead rebuilds

Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system.

A recent asset health condition assessment identified a total of **60 areas** within NPEI's service territory that require complete overhead rebuilds**.** Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section.

This program is intended to contribute to the "betterment" of the overhead system by;

- Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and;
- Improving system aesthetics with new and taller poles.

On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's current approach would rebuild **40 out of 60 areas** in the 2021 to 2025 period.

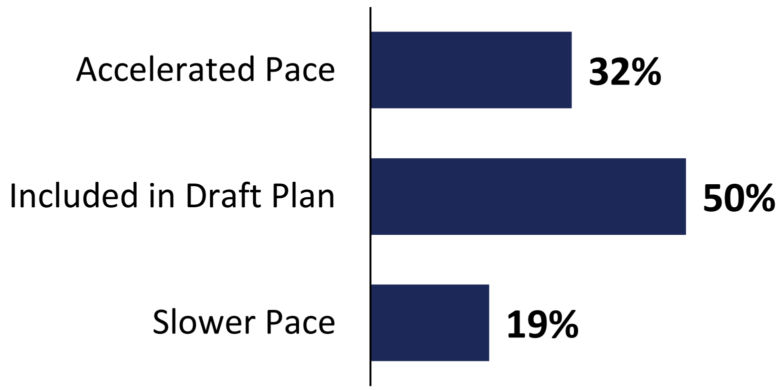
NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.

Option	Overhead rebuilds	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	61 km by 2025 (12.2 km per year)	Rebuild 12.2 km per year or approximately 10 projects per year
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	48.5 km by 2025 (9.7 km per year)	Rebuild areas with assets that have been identified as very poor in Asset Condition Assessment. Rebuild 9.7 km per year or approximately 8 projects per year
Slower Pace ***Decrease*** *of $0.03 per month annually ($0.36 less per year)*	36 km by 2025 (7.2 km per year)	Rebuild 7.2 km per year or approximately 6 projects per year

Representative Workbook

Overhead rebuilds

Q Which of the following options do you prefer?



n= 1,264

Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Accelerated Pace	34%	28%	24%
Included in Draft Plan	47%	55%	57%
Slower Pace	19%	17%	19%

Bill Impact on Finances	Significant impact	Impact	No Impact
Accelerated Pace	26%	31%	35%
Included in Draft Plan	39%	50%	53%
Slower Pace	35%	19%	12%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Accelerated Pace	33%	27%	37%
Included in Draft Plan	41%	53%	49%
Slower Pace	26%	20%	14%

Representative Workbook

Additional Feedback: Overhead rebuilds

Q Additional Feedback (Optional)

Additional Feedback (n=52) 96% of respondents did not provide additional feedback	**%**
Bury lines/better to replace with underground lines	35%
Reliability/safety outweighs cost	12%
Need more information	10%
Replace as necessary/most urgent first/run to fail	10%
Improve infrastructure/protect from animals	6%
Coordinate with pole replacement	5%
Replace within budget/find efficiencies/no increase to consumer	5%
Coordinate with other services/find other revenue streams/charge new developments	3%
Issue due to poor management/maintenance should have been ongoing	3%
Other	2%
None	8%

Representative Workbook

Background Information

Making Choices (7 of 7)

Grid modernization

New technology has changed the way that NPEI can manage and monitor the distribution system.

Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory.

This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event.

On average, since 2014, NPEI has installing approximately two remote devices per year, with focus on more rural, lower density areas. That said, there is an opportunity to install this monitoring and control equipment more quickly or slowly.

Option	Devices installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	20 devices (4 per year)	NPEI to double installation rate to four devices per year.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	10 Devices (2 per year)	Remain at current installation pace of two devices per year. Install new devices to expand NPEI's Smart Grid network. These devices provide better monitoring capability on the system, which leads to improved restoration times during outages.
Slower Pace ***Decrease*** *of $0.005 per month annually ($0.06 less per year)*	5 Devices (1 per year)	NPEI to cut rate of installation in half to one device per year.

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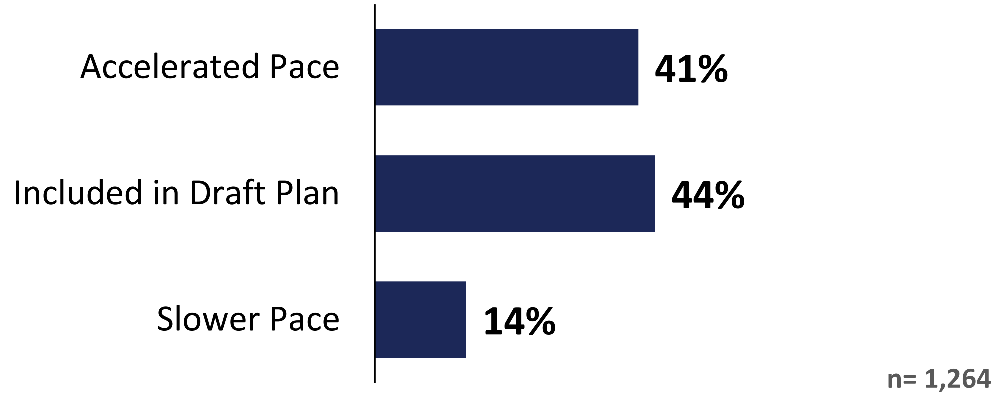
Grid modernization

Q Which of the following options do you prefer?



Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Accelerated Pace	43%	38%	38%
Included in Draft Plan	41%	52%	50%
Slower Pace	16%	10%	12%

Bill Impact on Finances	Significant impact	Impact	No Impact
Accelerated Pace	26%	38%	50%
Included in Draft Plan	38%	47%	44%
Slower Pace	36%	15%	6%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Accelerated Pace	41%	34%	46%
Included in Draft Plan	32%	49%	45%
Slower Pace	27%	17%	9%

Representative Workbook

Additional Feedback: Grid modernization

Q Additional Feedback (Optional)

Additional Feedback (n=49) 96% of respondents did not provide additional feedback	**%**
Be proactive/pay now to save later/costs will only increase	29%
Reliability/safety outweighs cost/protect grid/upgrade	16%
Only affected customers should pay	5%
Keeping consumer costs low should be a priority/cost already high	4%
Replace as necessary/most urgent/	2%
Replace within budget/find efficiencies	2%
Cost acceptable	1%
Other	23%
None	17%

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Impact of Choices

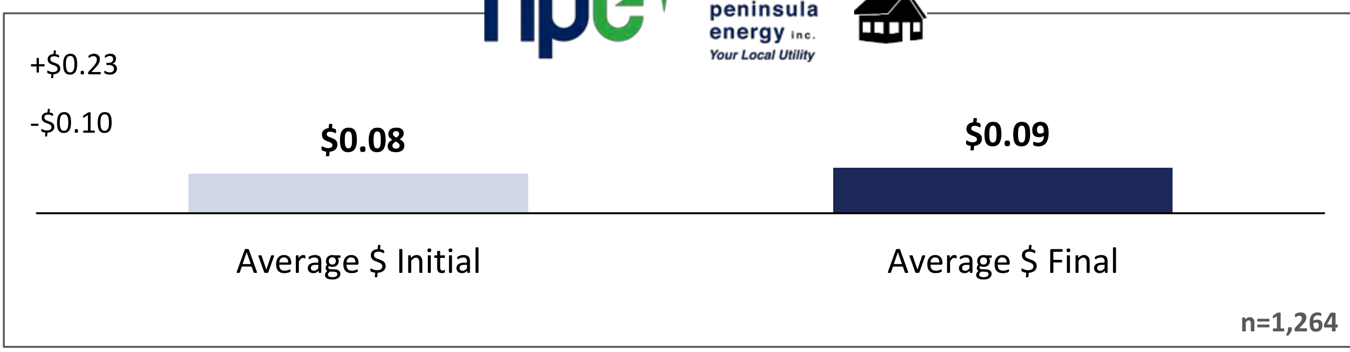
Investment Alternative Summary

Throughout this workbook, you have been asked about **seven key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page you will find the total bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential rate impact will be re-calculated. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Q Residential Customer Bill Impact Change and Magnitude of Bill Impact (**MEAN**)



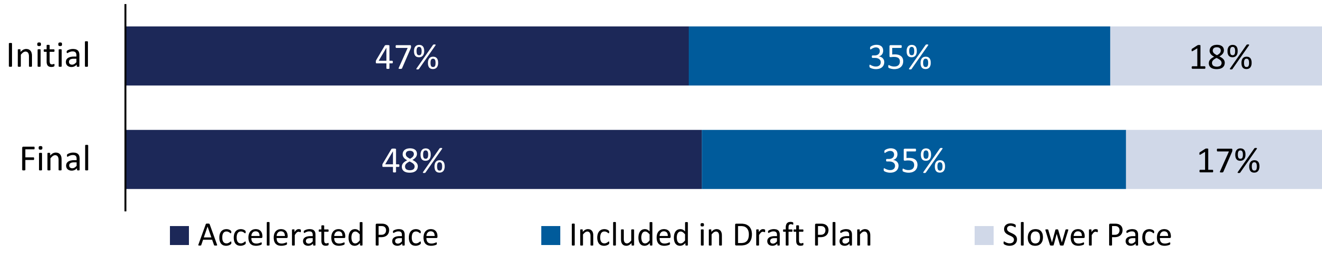
Differences that are statistically significant at 95% are noted by an asterisk (*).

Representative Workbook

Change in Initial vs. Final Response by Project

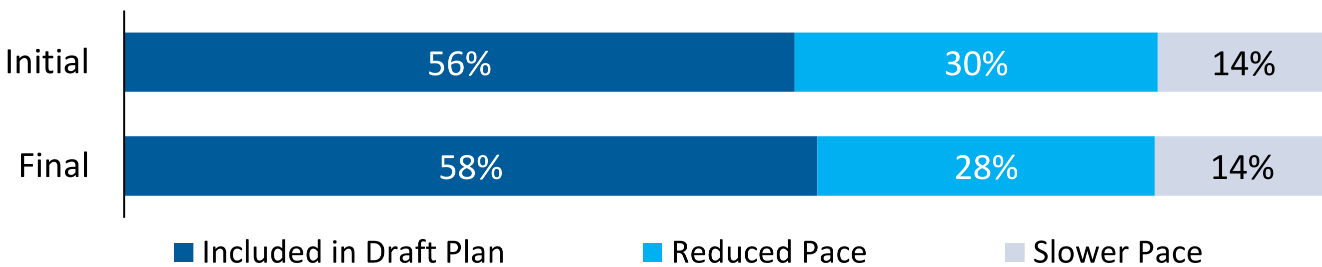
Residential

Q Overhead Pole Replacement

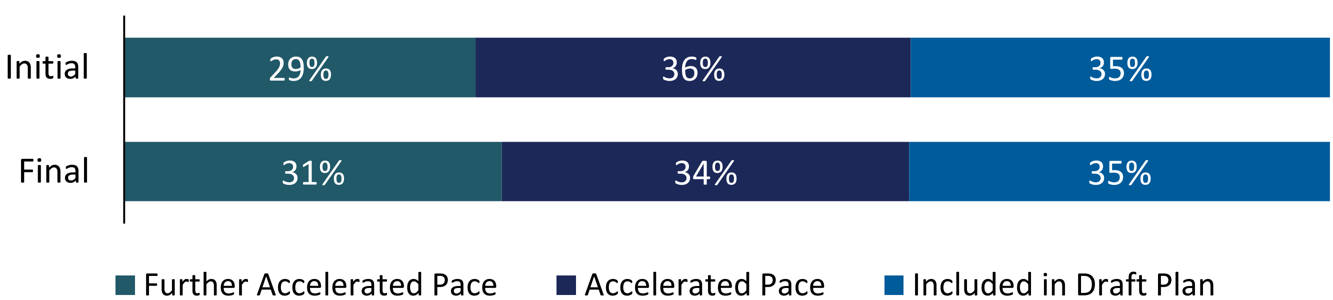


Q Overhead Transformer Replacement

Q Converting Outdated Underground Kiosk Transformers



Q Underground Cable Replacement



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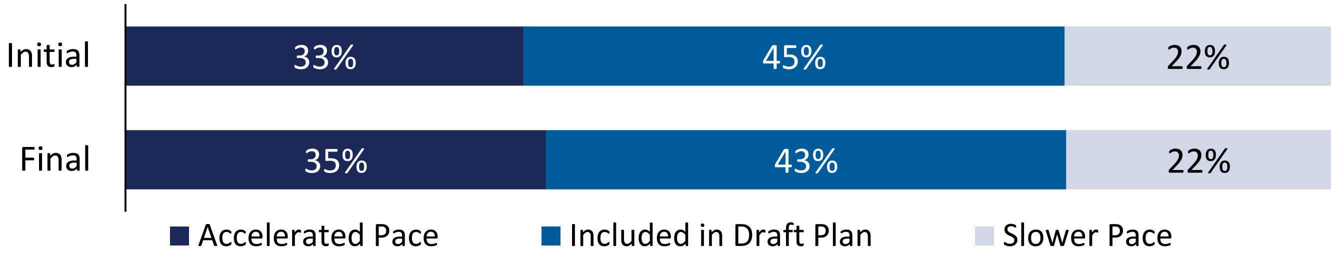
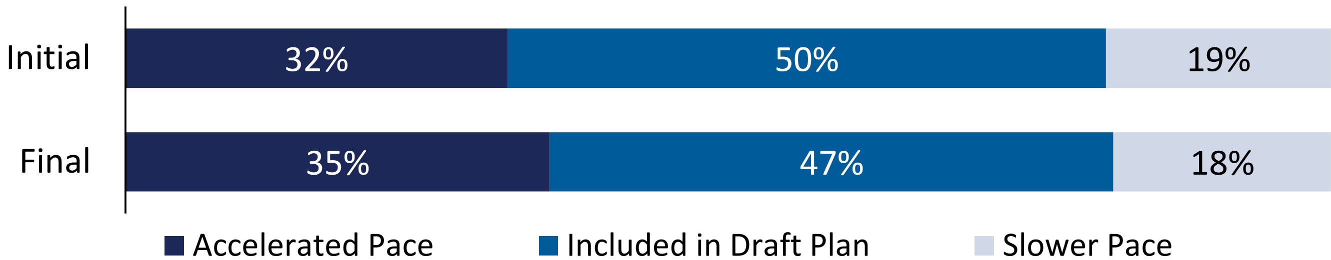
Change in Initial vs. Final Response by Project

Residential

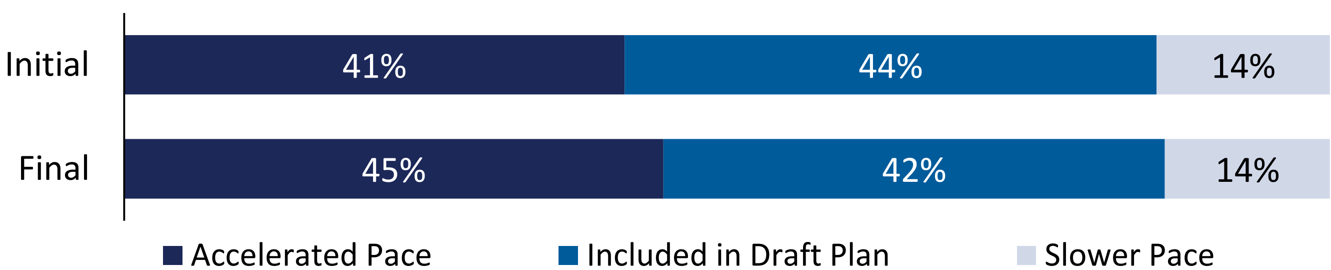
Q Subdivision Underground Rehabilitation



Q Overhead Rebuilds



Q Grid Modernization



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Impact of Choices

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Again, it is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $2.53 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by $4.29.
- As a result, the distribution charges on the typical residential customer's monthly bill would increase from $33.51 in 2020 to $37.80 by 2025.

Estimated Typical Residential Annual Increase in Monthly Bill (5 year forecast)

	Year	Average Residential Bill	Distribution Portion of Bill	Incremental Rate Change	% Change * (on distribution portion of bill)
Current Rate	2019	$113.32	$33.11		
Budgeted Rate	2020	$115.03	$33.51	$0.40	1.21%
Forecast for next rate period	2021	$116.33	$36.04	$2.53	7.55%
	2022	$118.08	$36.47	$0.43	1.20%
	2023	$119.85	$36.91	$0.44	1.20%
	2024	$121.65	$37.35	$0.44	1.20%
	2025	$123.47	$37.80	$0.45	1.20%
				$4.29	

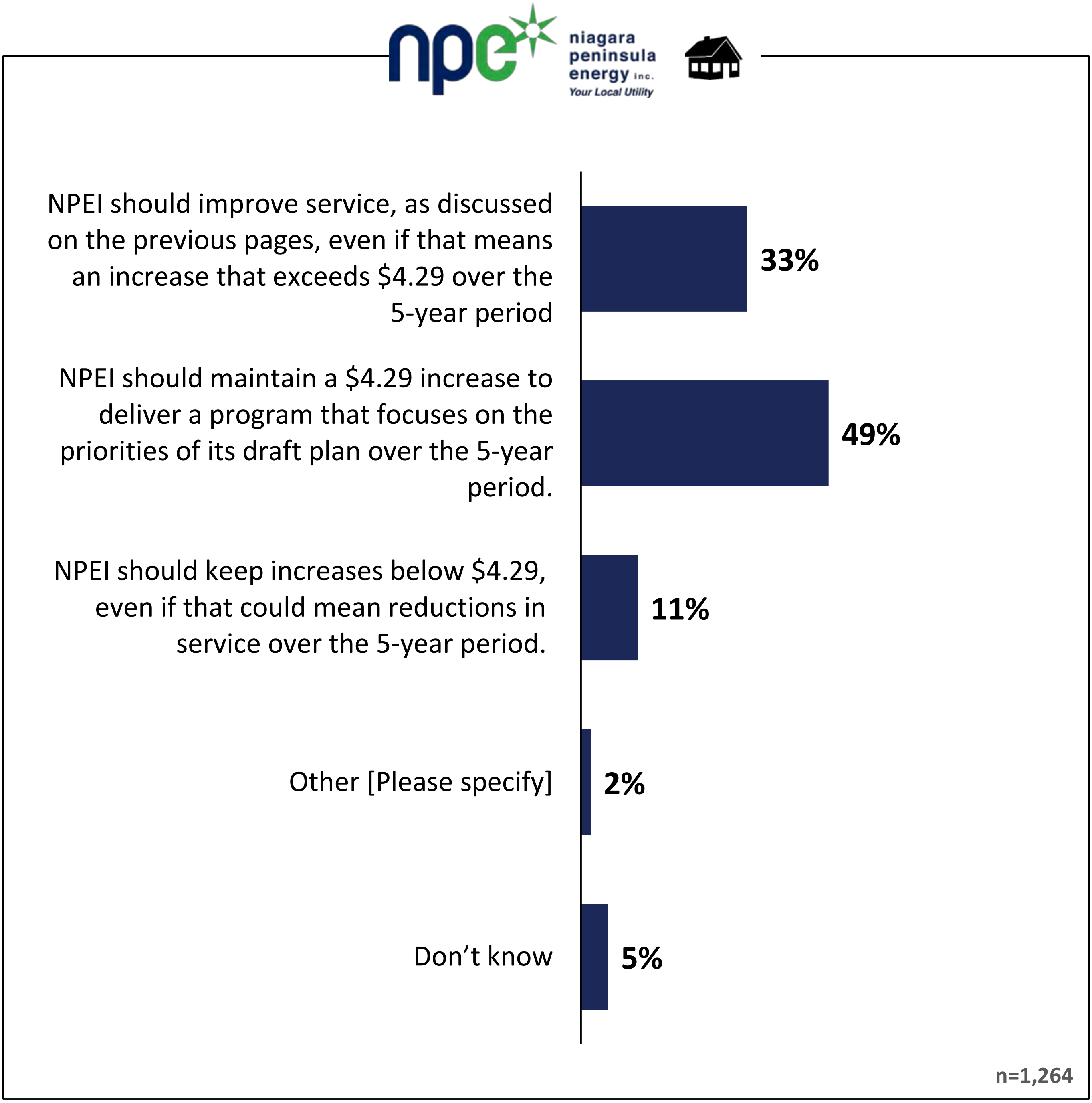
*** These estimates are preliminary, and are subject to your feedback as the business plan is finalized .**

INNOVATIVE RESEARCH GROUP

Representative Workbook

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

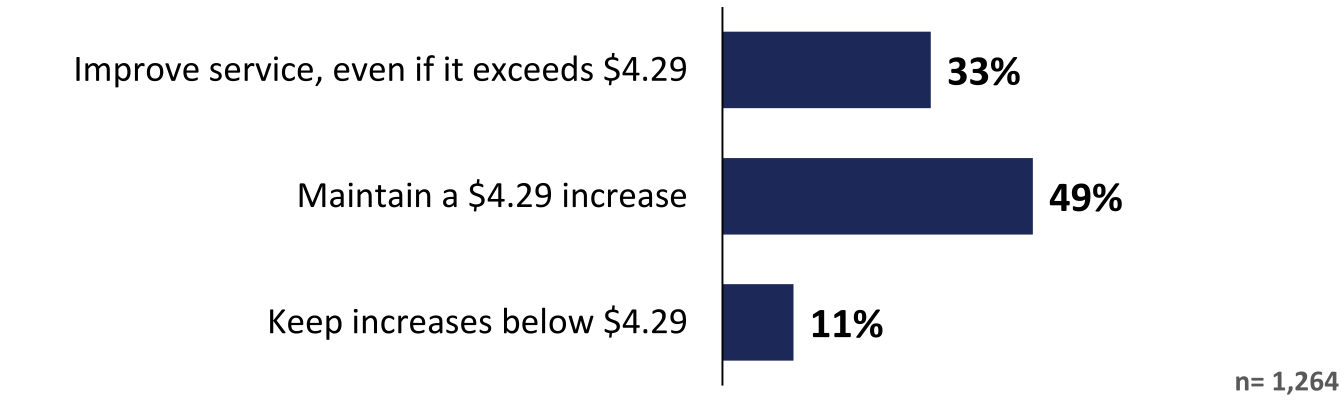
Q Considering what you know about Niagara Peninsula Energy's draft plan – which would see the typical residential customer's distribution portion of their bill increase by $4.29 over the 5-year period – which of the following best represents your point of view?



Representative Workbook

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Q Which of the following best represents your point of view?



Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Improve service	34%	32%	26%
Maintain increase	46%	56%	56%
Keep increases below	12%	8%	12%

Bill Impact on Finances	Significant impact	Impact	No Impact
Improve service	17%	27%	43%
Maintain increase	36%	55%	50%
Keep increases below	29%	13%	3%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Improve service	28%	27%	39%
Maintain increase	41%	52%	48%
Keep increases below	16%	13%	8%

Representative Workbook

Final Comments

Q Thinking about your answer to the previous question, why do you feel that NPEI should take that approach over the 2021-2025 period?

Final Comments (n=370) 71% of respondents did not provide additional feedback	**%**
Proactive approach-Pay now to ensure proper maintenance and prevent higher cost in the future	40%
Increase is reasonable -taking affordability into account	30%
Rates are high enough already/no increase	8%
Prioritize necessary improvements /repair as needed	3%
Unforeseen issues and maintenance should have already been planned in current budget	3%
Look for efficiencies to offset cost	2%
Service reliability should be priority	2%
Need more information	1%
Find alternative funding-Customers should not bear cost increase	1%
Balance approach	1%
Other	7%
None	2%

Q Do you have any final comments regarding NPEI or the customer engagement that you just completed?

Final Comments (n=171) 86% of respondents did not provide additional feedback	**%**
Positive - General NPEI/Survey/ asking for Customer input/informative	35%
Invest now to avoid higher cost in the future/Maintain and repair accordingly	20%
Cost issues/delivery fees/High rates/keep cost low	14%
Alternative energy sources/Turbine/Solar	3%
Negative-General	2%
Transparency-future planning	1%
Other	14%
None	12%

Representative Workbook

Final Thoughts: Workbook Diagnostics

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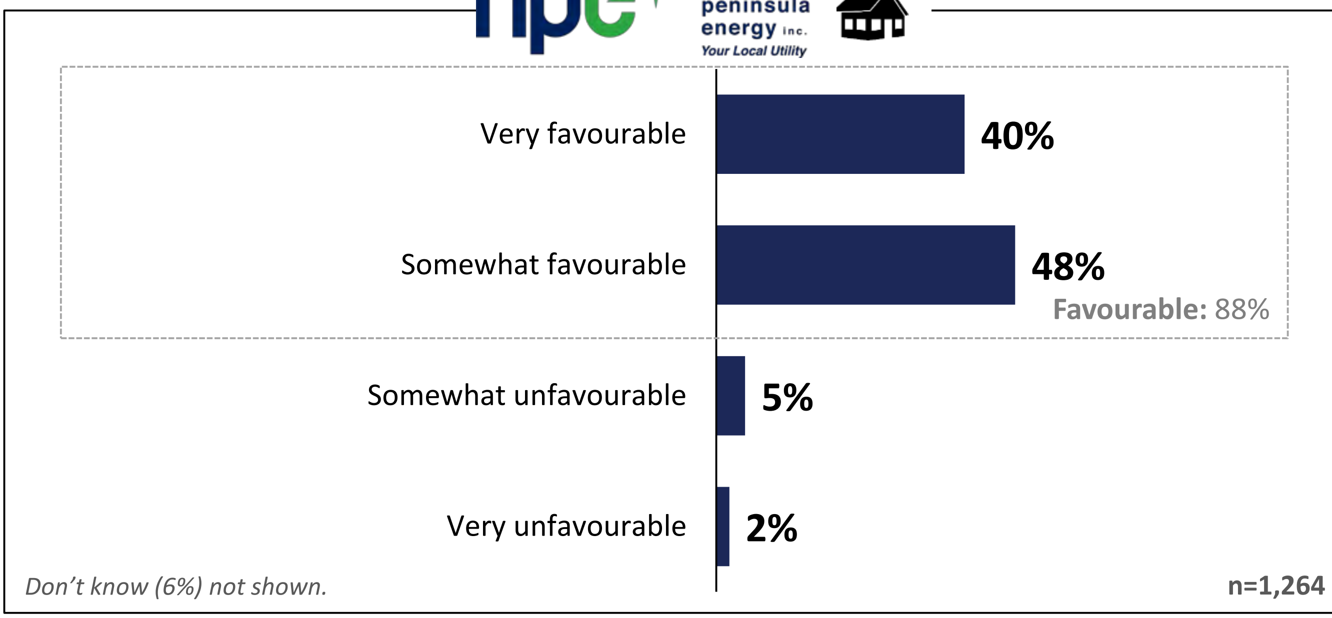
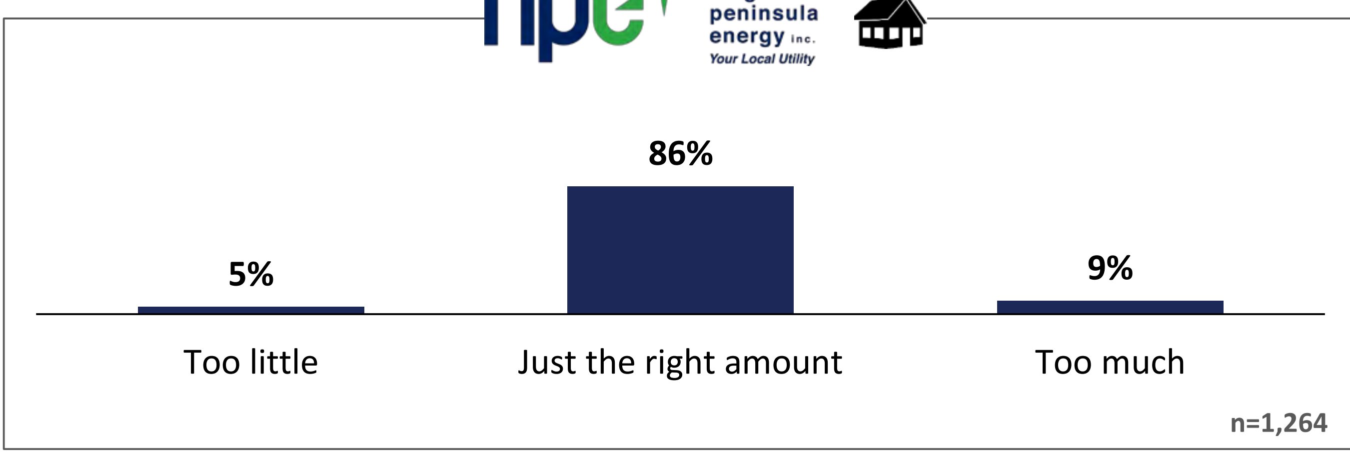
Q **Overall Impression**: Overall, did you have a favourable or unfavourable impression of the consultation you just completed?



Q **Volume of Information:** In this consultation, do you feel that NPEI provided too much information, not enough, or just the right amount?



Representative Workbook

Content Covered and Unanswered Questions

Q Was there any content missing that you would have liked to have seen included in this consultation?

Content Covered (n=1,264)	%
None	90%
Operating costs/Executive-Salaries/bonuses	1%
Alternative energy sources/Turbine/Solar/renewable	1%
Cost/delivery fees/High rates/keep cost low	1%
transparency/breakdown of cost allocation	1%
More information on system reliability aging infrastructure/preventative measures	1%
Billing issues/clearer breakdown/electronic	1%
Other	3%

Q Is there anything that you would still like answered?

Unanswered Questions (n=1,264)	%
None	93%
Cost issues/delivery fees/High rates/keep cost low	2%
Operating costs/Executive-Salaries/bonuses	1%
Power outage information	1%
Other	2%

Small Business Customers

Online Workbook Results

INNOVATIVE was engaged by NPEI to gather input on preferences on program timing and balancing outcomes. **Pages 71 to 112** show the actual pages of the workbook that was sent and completed by customers. The only additions are the actual results.

Field Dates & Workbook Delivery

The **Small Business Online Workbook** was sent to all Niagara Peninsula Energy small business customers who have provided the utility with an email address. Customers had an opportunity to complete the workbook between **November 25th and December 27th, 2019**.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the small business workbook was sent to **1,446** customers via e-blast from INNOVATIVE.

Small Business Online Workbook Completes

A total of **56** (unweighted) Niagara Peninsula Energy small business customers completed the online workbook via a unique URL.

Sample Weighting

The small business online workbook sample has been weighted proportionately by region and consumption quartiles in order to be representative of the broader Niagara Peninsula Energy service territory.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by region and quartile.

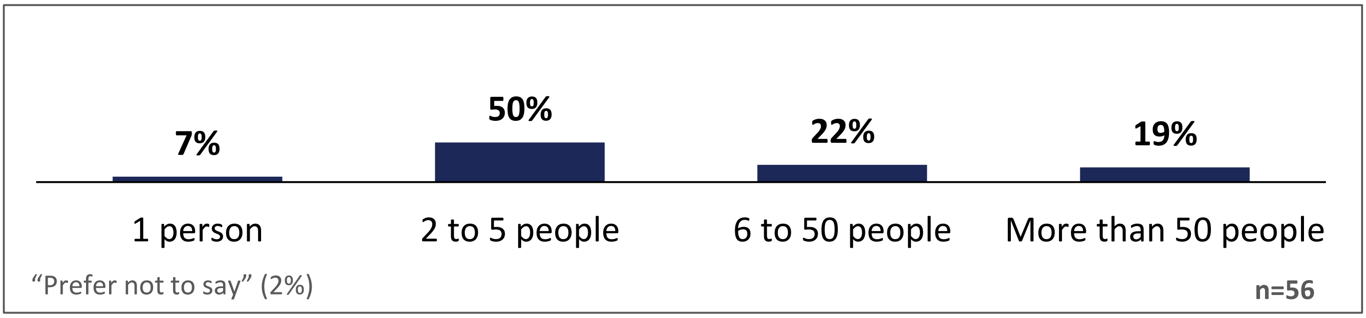
Region	Consumption Quartiles				Total	Distribution
	Low	Medium-Low	Medium-High	High		
Niagara Falls/Pelham	9 (9)	10 (9)	5 (9)	8 (9)	32 (36)	57% (64%)
Lincoln/West Lincoln	5 (5)	5 (5)	7 (5)	7 (5)	24 (20)	43% (36%)
Total	14 (14)	15 (14)	12 (14)	15 (14)	56 (56)	**100%**

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

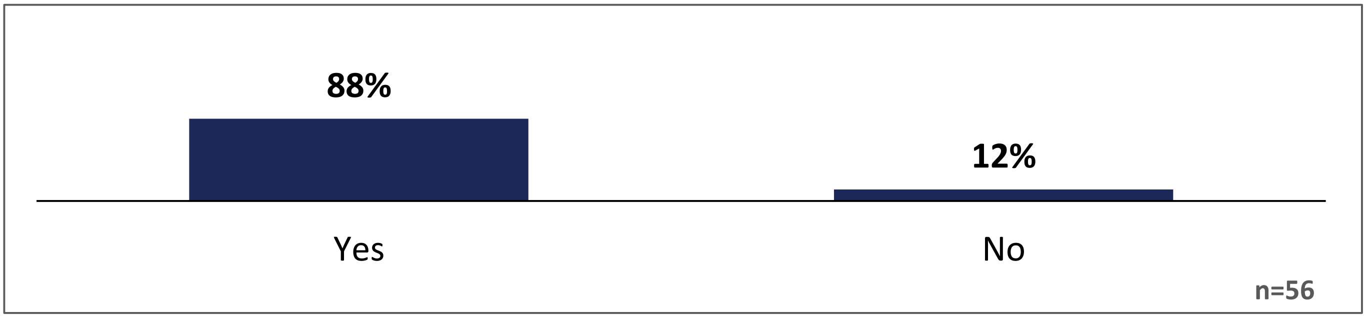
Representative Workbook

Demographic Breakdown

Q Company Size



Q Responsibility for Managing or Overseeing Organization's Hydro Bill



Q Sector

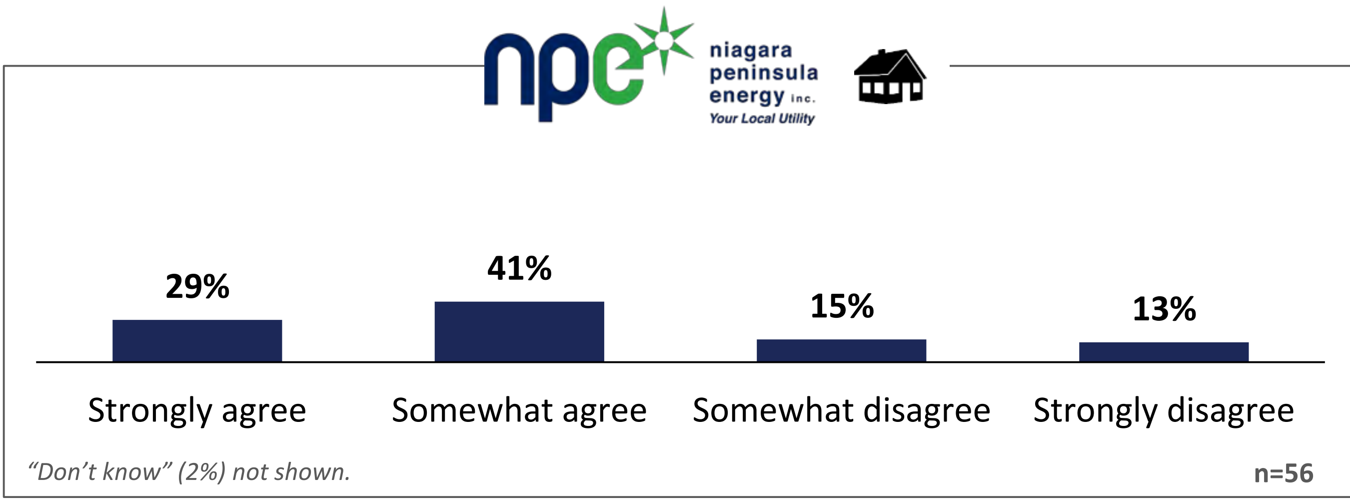
Sector	n-size	Sector	n-size
Commercial	14	Manufacturing/Industrial	2
Retail	12	Hospitality	2
Agriculture/Farm	7	Data Centre	2
Professional Services	5	School	1
Property Management	5	Restaurant/Tavern	1
Not-for-Profit/Church	3	*Prefer not to say*	3

Representative Workbook

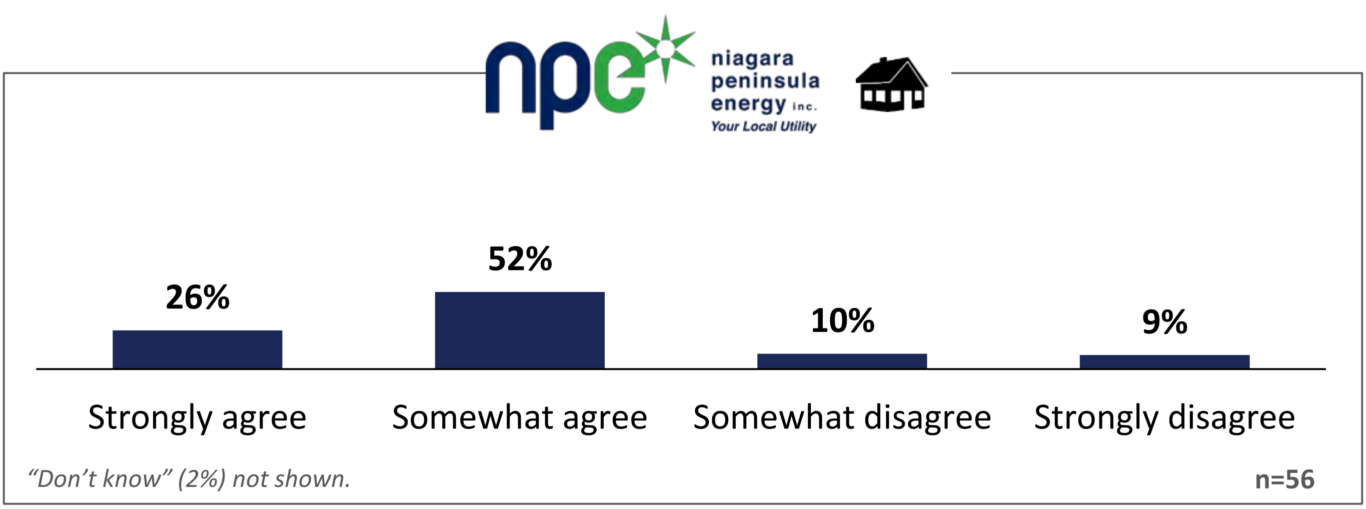
Environmental Controls

Thinking generally about the electricity system in Ontario, including generation, transmission and local distribution, do you agree or disagree with the following statements?

Q The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



Q Customers are well served by the electricity system in Ontario.



About this Consultation

Welcome to Niagara Peninsula Energy's Customer Engagement!

Niagara Peninsula Energy (NPEI) needs your input on choices that will impact the services you receive and the rates that you pay.

- **NPEI** is developing its investment plan for 2021 to 2025. This plan will determine the investments NPEI will make in equipment and infrastructure; the services it provides; and the rates you pay.
- As **NPEI** plans for the future, they want to ensure their business decisions are aligned with customers priorities, preferences, and needs.
- Throughout this survey, information will be provided in an effort to give you more background on which to base your responses.
- While responding to the following questions, remember that there are no wrong answers, and that your individual responses will remain anonymous.
- This customer engagement will take approximately 25-35 minutes to complete, depending on the level of feedback you wish to provide. Your progress will be saved as you move through the workbook, meaning you can leave and return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired NPEI to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one (1) $500 cash prize.

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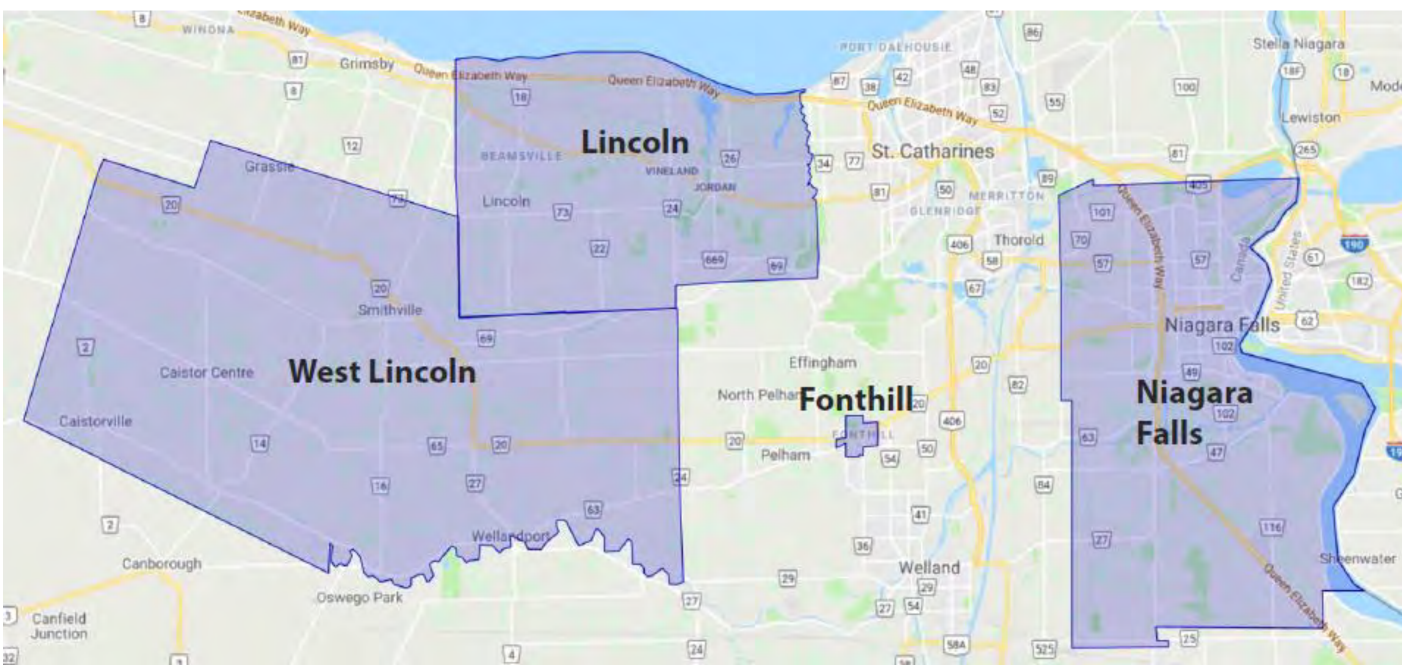
Electricity 101

Who is Niagara Peninsula Energy?

NPEI provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham, and Township of West Lincoln.

- NPEI serves an area of approximately 827 square kilometers and a customer base of approximately 55,600 residential and business customers, containing a mix of urban and rural electrical distribution.
- NPEI is jointly owned by the municipalities it services.
- NPEI manages all aspects of the electricity distribution business and is regulated by the Ontario Energy Board (OEB).
- As a local distribution company (LDC) and regulated entity, NPEI applies for, and receives approval from the regulator to charge for its services.



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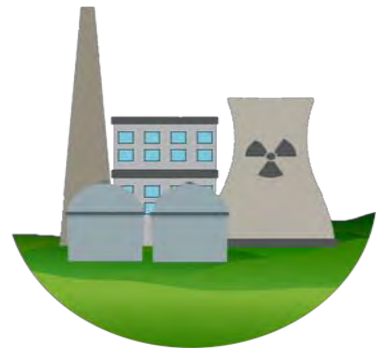
Electricity 101

Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

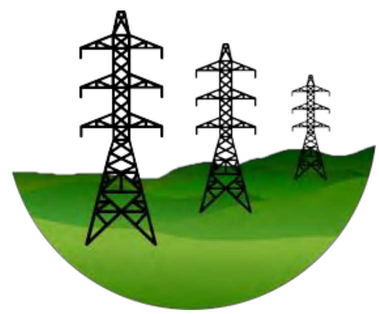
Where electricity comes from



Ontario's electricity is generated using a mix of nuclear, gas-fired, and water power (hydro), as well as biomass and renewable sources such as wind and solar technology. In Ontario, a number of companies own these generating stations but approximately half of the electricity is generated by Ontario Power Generation. The Independent Electricity System Operator (IESO) balances the supply of, and demand for, electricity on a second-by-second basis and directs its flow across the high-voltage transmission lines.

Transmission

How electricity travels across Ontario



Once generated, electricity must be transported to electrical substations across the province. Due to the large amount of power and long distances, transmission normally takes place at high voltages with the lines suspended on large, steel towers. The province has more than 30,000 kilometres of 'electricity highway', most of which is owned and operated by Hydro One.

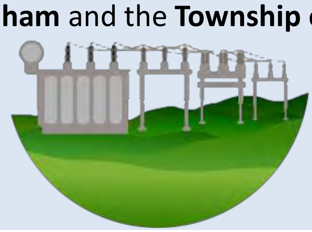
Local Distribution

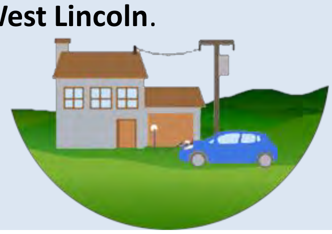
How electricity is delivered to the end-consumer

NPEI is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, NPEI delivers electricity to approximately 55,600 residential and business customers.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.





npe niagara peninsula energy inc.
Your Local Utility

Representative Workbook

Familiarity with Ontario’s electricity system

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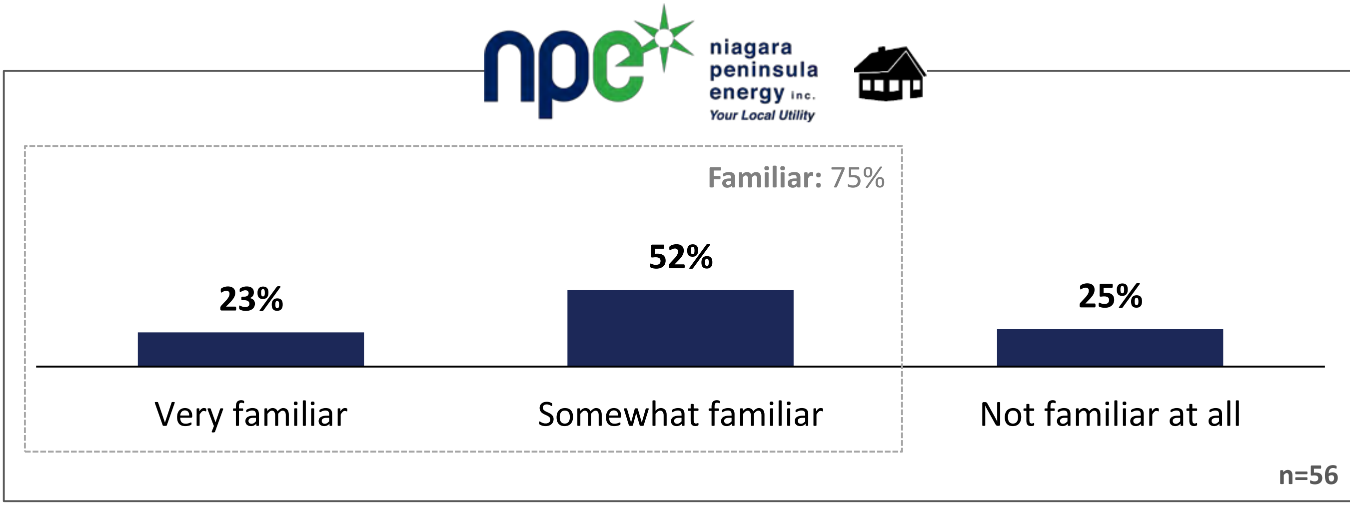
Q Before this survey, how familiar were you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?



Representative Workbook
Background Information

Electricity 101

How much of my electricity bill goes to Niagara Peninsula Energy?

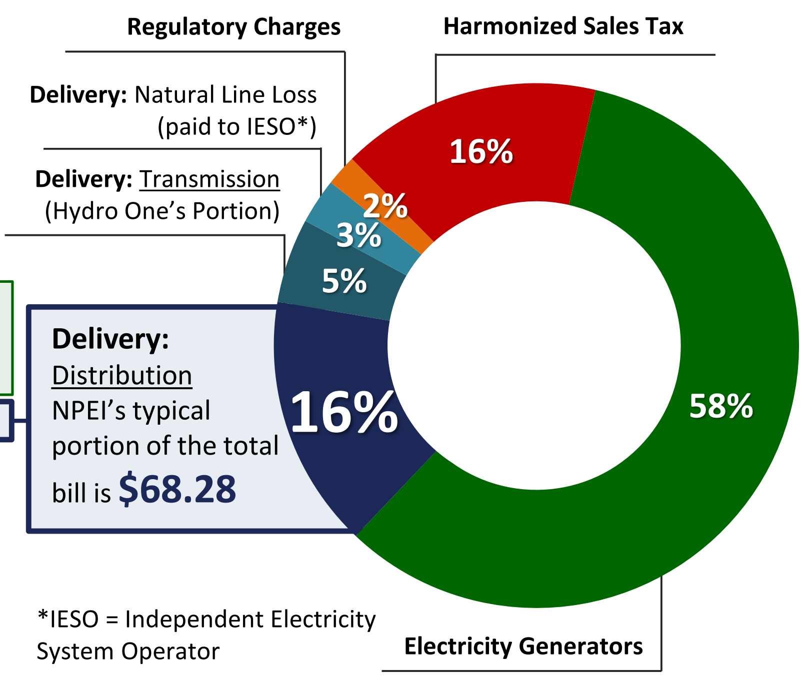
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge.
- Distribution makes up about **16%** of the typical small business customer's bill.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

NPEI Sample Monthly Bill*
(Based on monthly usage of 2,000 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Off-Peak @ 10.1 ¢/kWh	129.28
Mid-Peak @ 14.4 ¢/kWh	51.84
On-Peak @ 20.8 ¢/kWh	74.88
Delivery	103.35
Regulatory Charges	8.42
Total Electricity Charges	**$367.77**
HST	47.81
Ontario Electricity Rebate*	**(-$116.95)**
Total Amount	**$298.63**



*IESO = Independent Electricity System Operator

* As of November 1, 2019. Chart is based on total bill amount after applying the Ontario Electricity Rebate.

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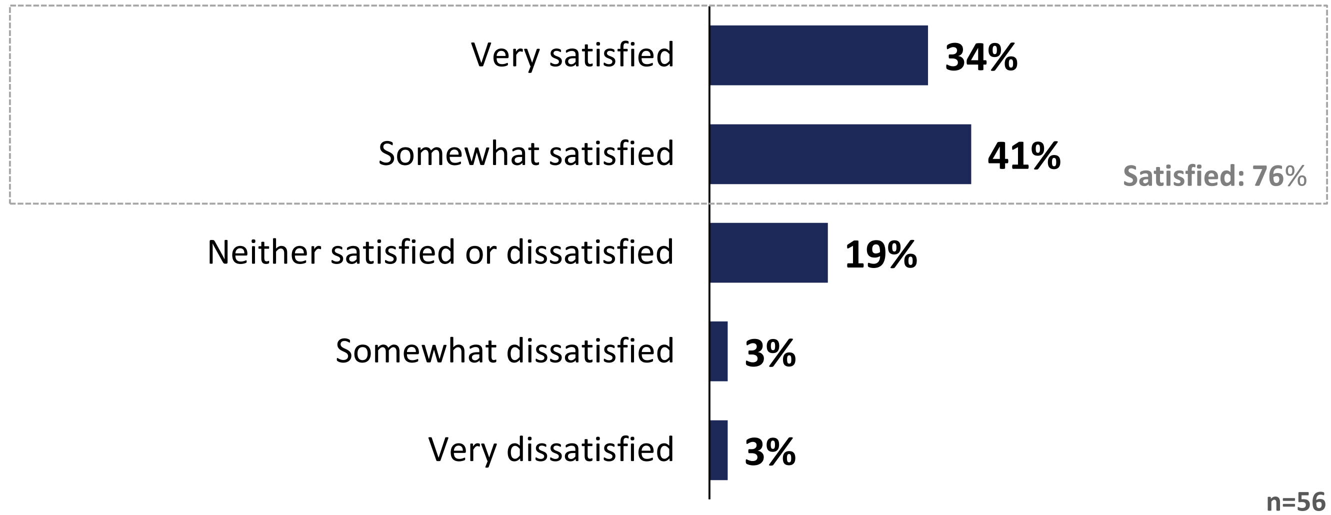
Overall Satisfaction with Niagara Peninsula Energy

Q Thinking specifically about the services provided to you and your community by Niagara Peninsula Energy, overall, how satisfied or dissatisfied are you with the services that your organization receive?



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Familiarity with Percentage if Bill Remitted to NPEI

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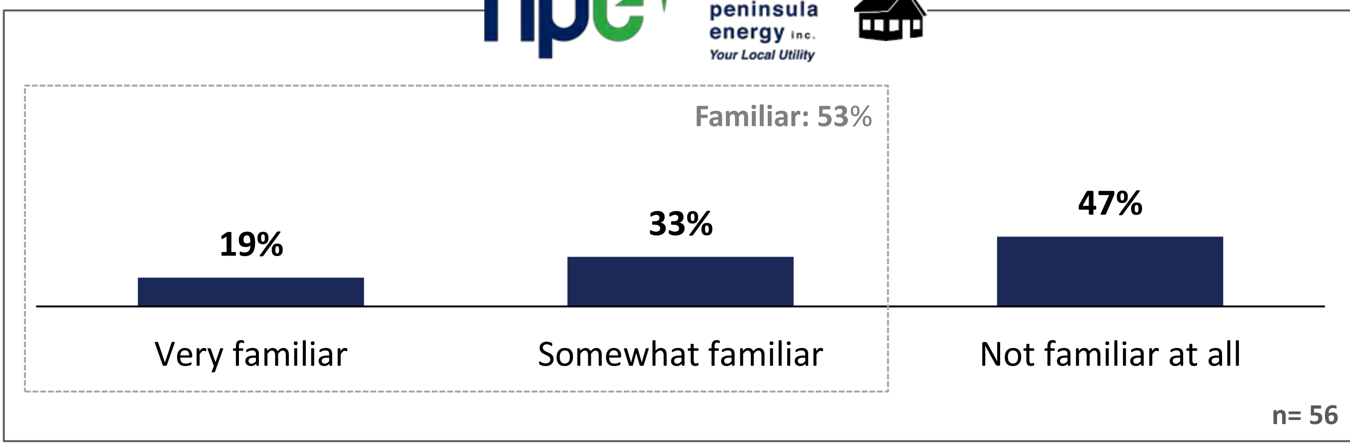
Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Niagara Peninsula Energy?



Q Is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to your organization?

Improving Services (n=17) 70% of respondents did not provide additional feedback	**n-size**
Improve billing - clarity/payment terms/methods/website	4
Decrease/eliminate delivery charges	3
Improve reliability/less outages	2
Lower rates/Charge less	1
Do not increase rates/keep rates affordable	1
Provide more info on energy consumption/conservation/renewables	1
Invest in infrastructure/move cables underground	1
None	4

Niagara Peninsula Energy Background

Building Niagara Peninsula Energy's draft plan

NPEI has put together its draft business plan based on the information and input from various sources, such as:

- **Legal and regulatory** requirements by continuing to meet its obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected through both ongoing dialogues and specific engagements, such as this.

There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their businesses and serve their customers.

- **Policy**: The Ontario Ministry of Energy, Northern Development and Mines (MNDM) creates energy policy for the province.
- **Regulation**: The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.
- **Operations and Planning**: The Independent Electricity System Operator (IESO) manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

Ontario ENERGY /ÉNERGIE

ONTARIO ENERGY BOARD

ieso Connecting Today. Powering Tomorrow.

Niagara Peninsula Energy Background

How did customer feedback shape Niagara Peninsula Energy's draft plan?

NPEI is placing more emphasis on incorporating customer feedback into the planning process than ever before.

NPEI engages with its customers both in day-to-day interactions and in a variety of customer engagement activities. These interactions help identify customer needs and preferences, and inform how the utility plans for the future.

This past summer, NPEI engaged with **thousands of residential and business customers** from across its service territory – both in person and through telephone and online surveys.

What did NPEI hear from customers like yourself?

1. The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates".

2. Among competing outcomes, **price**, **reliability**, and **finding internal cost efficiencies** are the top three priorities for both residential and small business customers.

3. While keeping price at a reasonable and affordable level is an important priority, many customers feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Considering this feedback, as well as the information and inputs discussed on the previous page, NPEI has developed a draft plan that is responsive to:

1. Legal requirements by continuing to meet its obligations, including safety and reliability;

2. A transformer station upgrade to accommodate the new Niagara South Hospital and future surrounding growth.

3. Mandatory service connections to accommodate new customers and customer-required upgrades, of which NPEI does not have control over how and when these costs are incurred.

4. Customer feedback by:

    a) Keeping distribution price increases as low as possible;

    b) Maintaining long-term performance for customers experiencing average or better service;

    c) Improving service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,

    d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

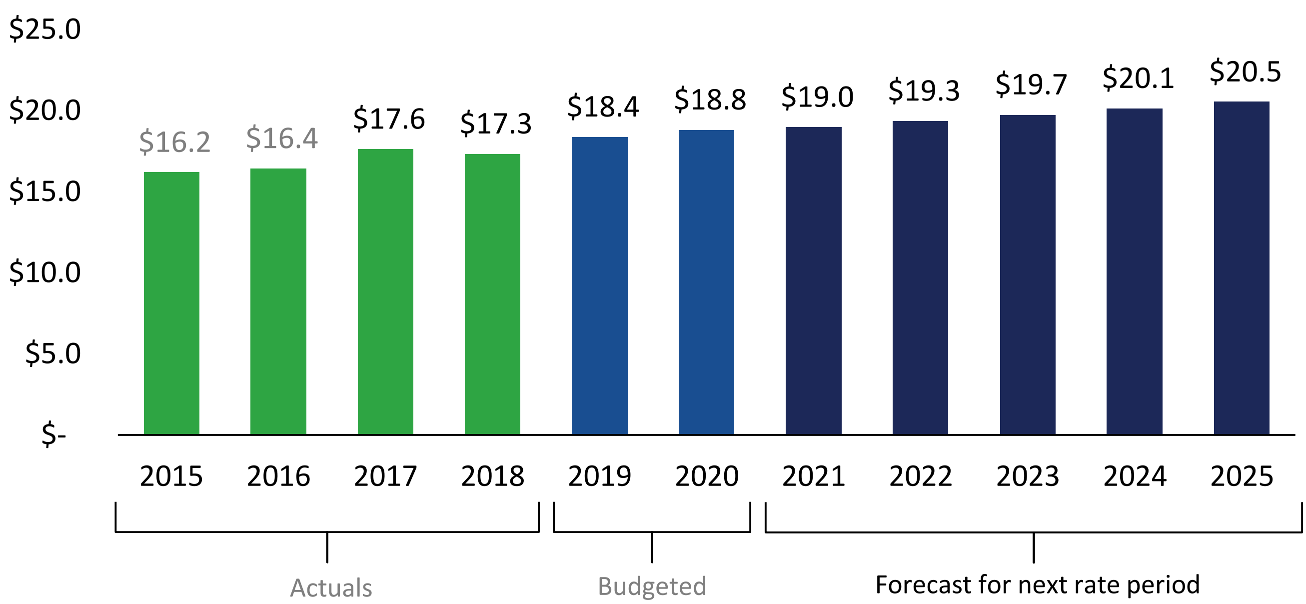
Niagara Peninsula Energy Background

Operating Expenses

In this section, we want to focus on operating expenses and how NPEI compares to its peers.

NPEI's operating budget covers recurring expenses, such as the maintenance of poles, wires, transformers, fleet and buildings as well as proactive maintenance programs such as tree trimming, and payroll for employees. Meter reading, postage, cyber security and hardware/software maintenance expenses are billing and customer service-related expenses. The proposed 5-year plan, between 2021 and 2025, would see NPEI spend an estimated total of $98.7 million on operations.

NPEI's Current and Forecasted Operating Expenses, per Year (Millions)*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

Representative Workbook

Background Information

Small Business

NPEI's **operating costs** are benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, NPEI's operating costs per customer was **$311.67**, which is slightly more than some, while less than both Hydro One and Canadian Niagara Power.

2018 Operating & Maintenance and Administration (OM&A) Per Customer ($)

The diverse geographical nature of NPEI's service territory, which is a mix of urban and rural communities is a large consideration/driver of these OM&A costs. In some parts of the service territory, there may be less than 30 customers per kilometer of line. Despite low density, these lines still require the same level of ongoing maintenance, including tree trimming and other expenses that contribute to operating the system; thereby resulting in a higher cost per customer.

Niagara Peninsula Energy Background

Operating Expenses

Recall, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge NPEI's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found at oeb.ca/participate.

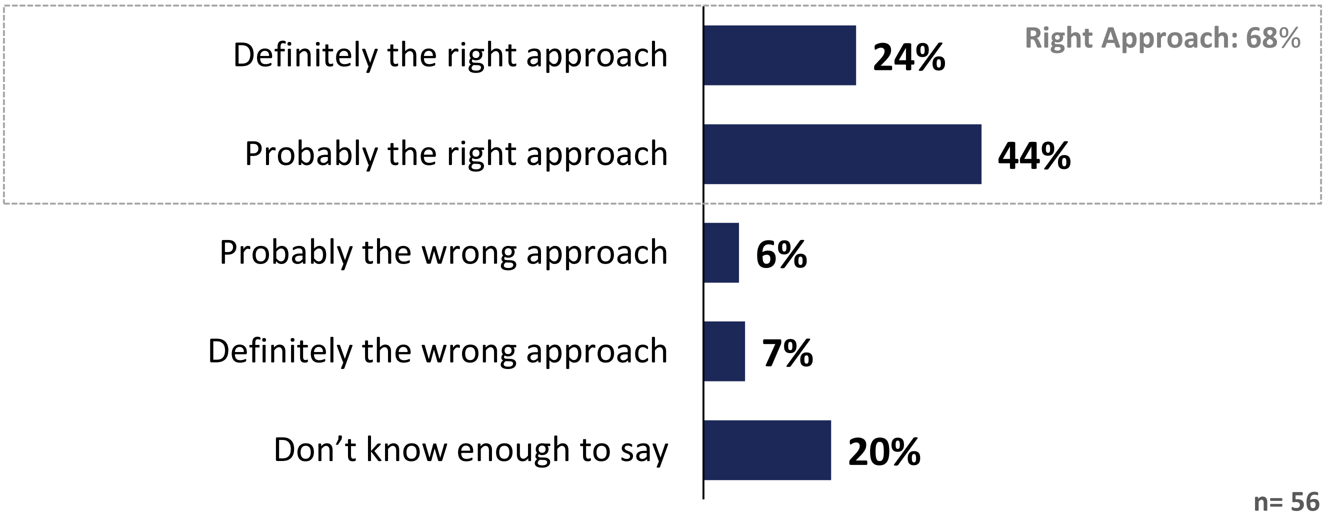
This customer engagement however, is focused on capital investments.

Detailed discussion of NPEI's operating budget is left to experts from the OEB and intervenors in the formal rate application review; this workbook focuses on collecting your view on competing trade-offs in capital investments.

Representative Workbook

Approach to Operating Expenses

Q Does leaving the detailed discussion about Niagara Peninsula Energy's operating budget to experts from the OEB and intervenors seem like the right approach or wrong approach to you?



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Niagara Peninsula Energy Background

Capital Investments

NPEI's **capital budget** covers items that, once purchased, have lasting benefits over many years. Year-over-year, regardless of external drivers, NPEI will need to make investments in the core distribution system, including poles, wires, cables and transformers.

Based on initial customer input and the approach outlined previously, NPEI believes the capital expenditure required to address system renewal, maintain system reliability and safety, and invest in other infrastructure priorities between 2021 and 2025 is estimated to be **$70.3 million**.

NPEI classifies the costs of four types of capital investment between 2021 and 2025. Each of these four investment categories helps NPEI pace and prioritize projects.

2021-2025 Forecasted Capital Investments

System Renewal ($38.2 million)

These projects are a mix of planned end-of-life replacements and emergency replacements.

Projects Include: Replacement of existing overhead wires, poles, and pole mounted transformers, underground cables and transformers and transformer station upgrades.

System Access ($17.1 million)

"Must do" investments that respond to customer requests for new connections or new infrastructure development.

Projects Include: NPEI's share of new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs.

General Plant ($8.4 million)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

Projects Include: Financial and customer IT systems, enhanced cyber security investments, facility renovations, backup generation, and vehicle replacements.

System Service ($6.6 million)

These investments consist of projects that address capacity constraints, improve system reliability and customer service.

Projects Include: Installation of automated switches and system expansion to supply new development.

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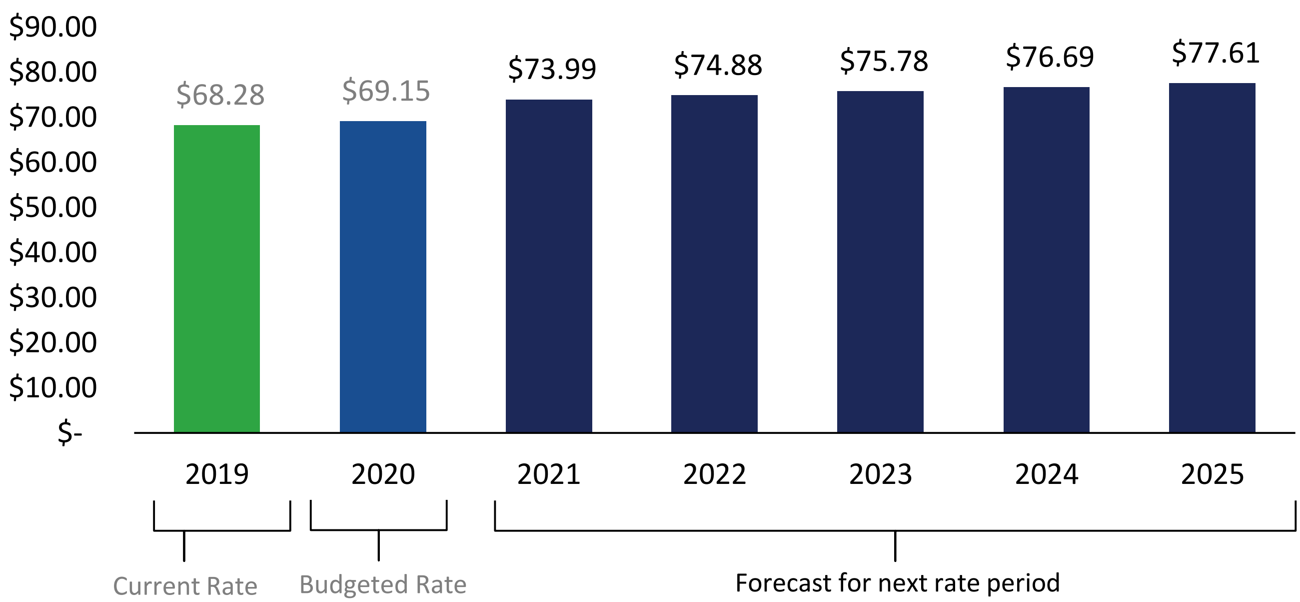
How much will this draft plan cost me?

Remember, the current typical NPEI small business customer's electricity bill is about $298 per month, of which $68.28 goes to NPEI.

It is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $4.84 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical small business customer would see the distribution portion of their electricity bill increase by $8.46.
- As a result, the distribution charges on the typical small business customer's monthly bill would increase from $69.15 in 2020 to $77.61 by 2025.

Estimated Small Business Monthly Distribution Charge, per Year*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI is looking for your input on its preliminary plan to ensure it is making the spending decisions that matter to you, the customer.

The following sections of this workbook will explore some of the choices Niagara Peninsula Energy needs to make to help finalize its preliminary plan.

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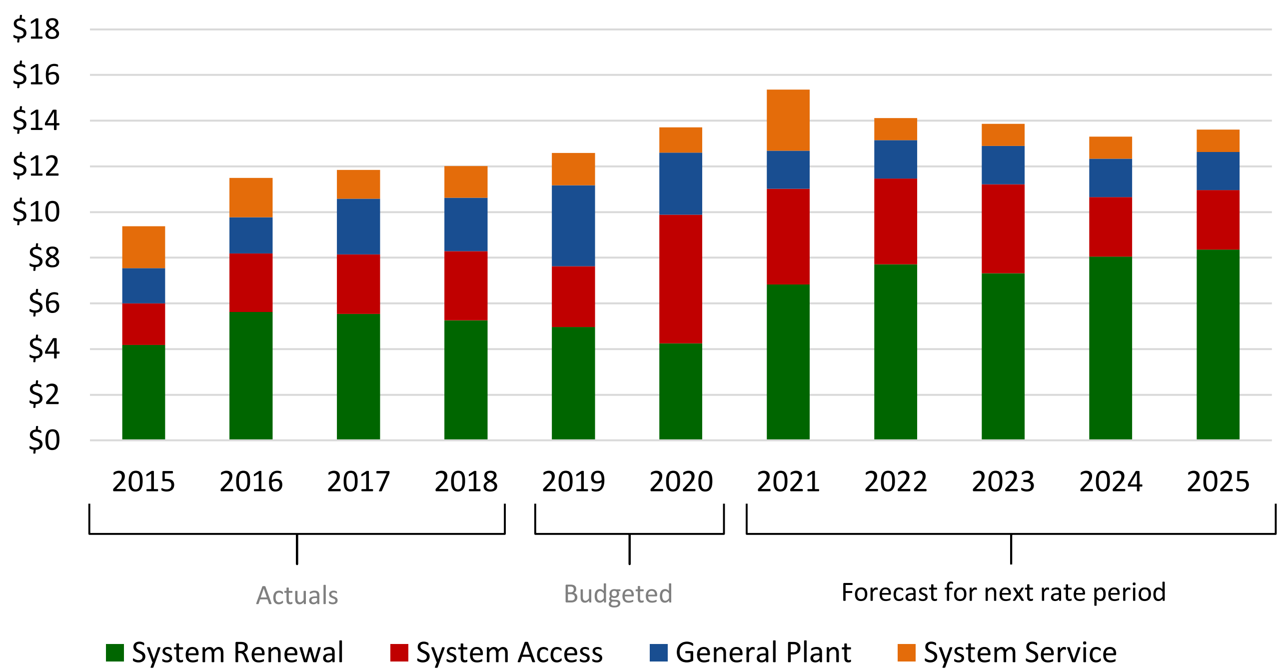
Niagara Peninsula Energy Background

Pacing Capital Investments

The overall amount NPEI invests in capital projects remains generally the same year over year, but what does change is where these investments are made. In some years, when unplanned or unforeseen investments are needed, NPEI will re-allocate funds to make room for these projects within the approved budget. This helps limit the overall amount that the distribution charges fluctuate year-over-year.

The chart below outlines NPEI's spending in past years, and proposed spending for the 5-year period 2021 to 2025.

2015 – 2025 Historical and Forecasted Capital Investments*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

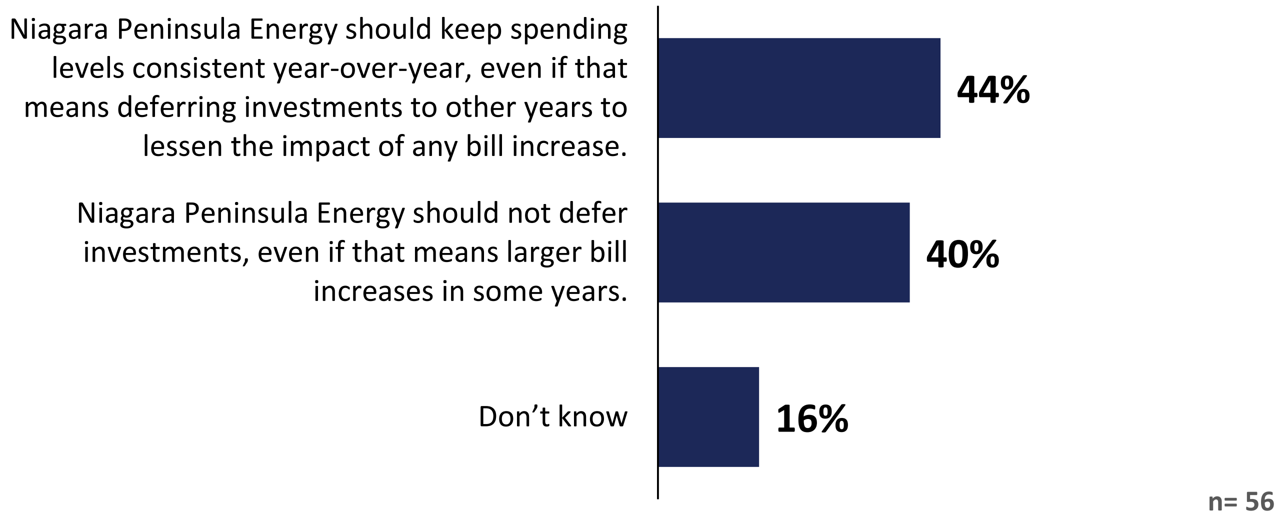
System Access expenditures are budgeted to increase to $5.6M in 2020 to accommodate a number of large commercial customer growth projects as well as municipal road work.

Representative Workbook

Approach to Pacing Investments

Small Business

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to pacing investments?



Q Additional Feedback (Optional)

Additional Feedback (n=8) 86% of respondents did not provide additional feedback	**n-size**
Deferring only increases future prices/invest now in technology and equipment	2
No increase-keep cost low too high already	2
Case by case basis/Prioritize spending on what is needed most	1
Reliability of services is paramount	1
None	3

Mandatory Investments

Federal, provincial, and municipal governments as well as regulators set requirements and standards that NPEI must satisfy. Mandatory investments can be broken down into three categories:

- **Connecting customers**: This includes connecting customers to the grid when a new home or building is constructed or modified.
- **Moving equipment**: This includes moving equipment like poles and cables for road widening.
- **Mandated obligations**: This includes installing and maintaining customer meters and transferring electricity from the provincial transmission system.

These mandatory investments mean that about **one-in-four dollars (23%)** of your distribution rates over the past five years have not been available for other non-mandatory investments. Looking forward to the 2021-2025 period, NPEI forecasts a similar level of mandatory investments, driven largely by:

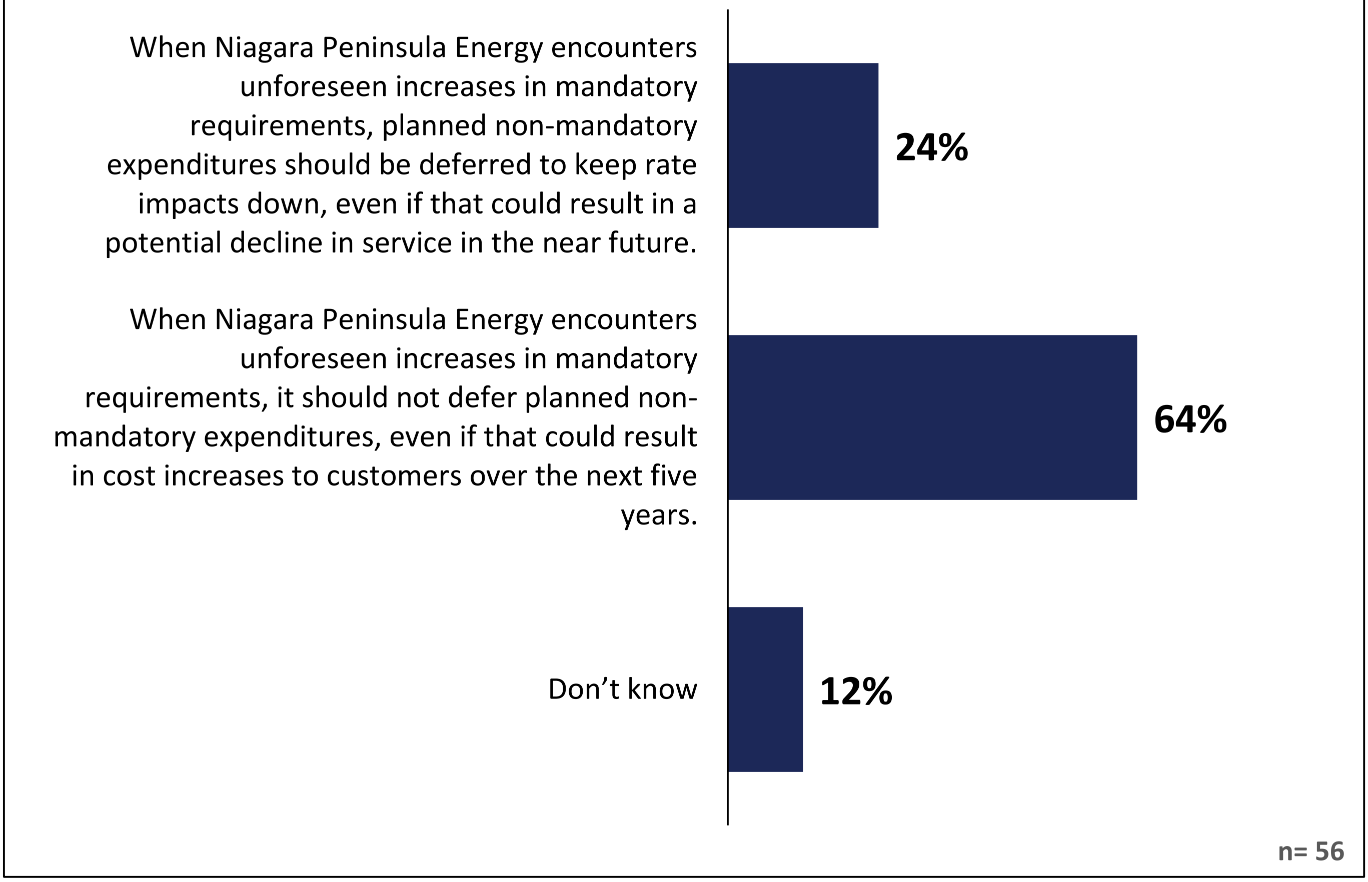
- **Preparing to connect the new Niagara South hospital;**
- **Work to accommodate the 2021 Canada Summer Games in the Niagara Region, and;**
- **Work to accommodate growth and future electricity capacity needs.**

Representative Workbook

Approach to Mandatory Investments

Small Business

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to mandatory and non-mandatory spending?



Q Additional Feedback (Optional)

Additional Feedback (n=8) 86% of respondents did not provide additional feedback	**n-size**
Increase within reason when expenditures are necessary/Balance over 5 years	3
Case by Case basis/New developers/builders/Company/2021 Canada Games/Government- should fund costs	2
Unforeseen increases should not be encountered/should already be in budget	2
None	1

Making Choices (1 of 7)

Overhead Pole Replacement

A recent asset health condition assessment shows that **575 or approximately 3%** of the poles in NPEI's distribution system are in *poor* or *very poor* condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a car accident.

On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period.

NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

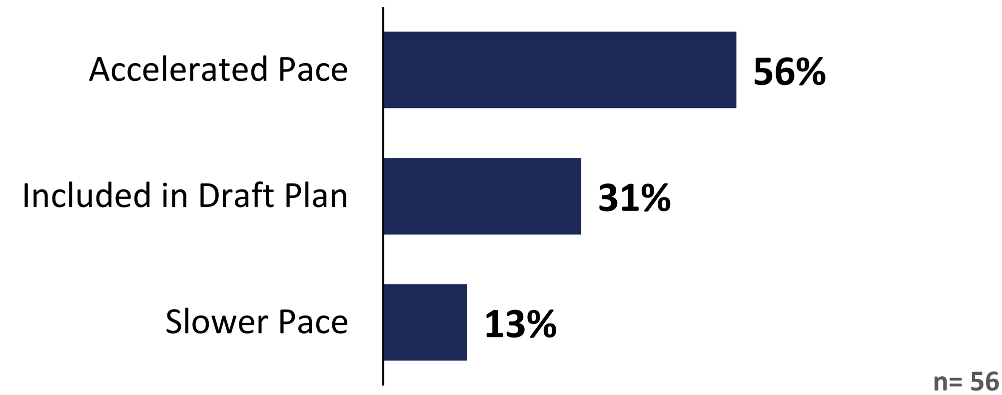
Option	Poles Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	1,000 by 2025 (200 per year)	Address the very poor and some of the poor condition poles identified in the Asset Condition Assessment.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	500 by 2025 (100 per year)	Address most of the very poor condition poles identified in the Asset Condition Assessment and annual pole inspections by 2025.
Slower Pace ***Decrease*** *of $0.02 per month annually ($0.24 less per year)*	250 by 2025 (50 per year)	Address only the poles in need of immediate replacement, as identified in the annual pole inspection report.

Representative Workbook

Overhead Pole Replacement

Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=6) 86% of respondents did not provide additional feedback	**n-size**
Be proactive/pay now to save later/costs will only increase	1
Bury lines/better to replace with underground lines	1
Reliability/safety outweighs cost	1
Investigate/Invest in new pole technology	1
Information misleading/skeptical about figures/inspection criteria	1
Coordinate with other services/find other revenue streams	1

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Overhead transformer replacement

Transformers are a critical piece of distribution equipment that reduce voltage from the higher levels that are more efficient to move electricity long distances to lower levels that are safer to connect to homes and businesses. They are typically either located on the ground, in underground vaults, or attached to distribution poles

A recent asset health condition assessment shows that **1,251 or approximately 21%** of the overhead transformers in NPEI's distribution system are in poor or very poor condition.

Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances.

However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses.

NPEI is proposing a new program to proactively replace **250 of the 677 or 37%** of the overhead transformers identified as very poor condition before they fail over the course of the next five years.

As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Option	Transformers Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	375 by 2025 (75 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	250 by 2025 (50 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	125 by 2025 (25 per year)	Address only the worst of the polemount transformers identified as very poor in the Asset Condition Assessment report.

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Overhead transformer replacement

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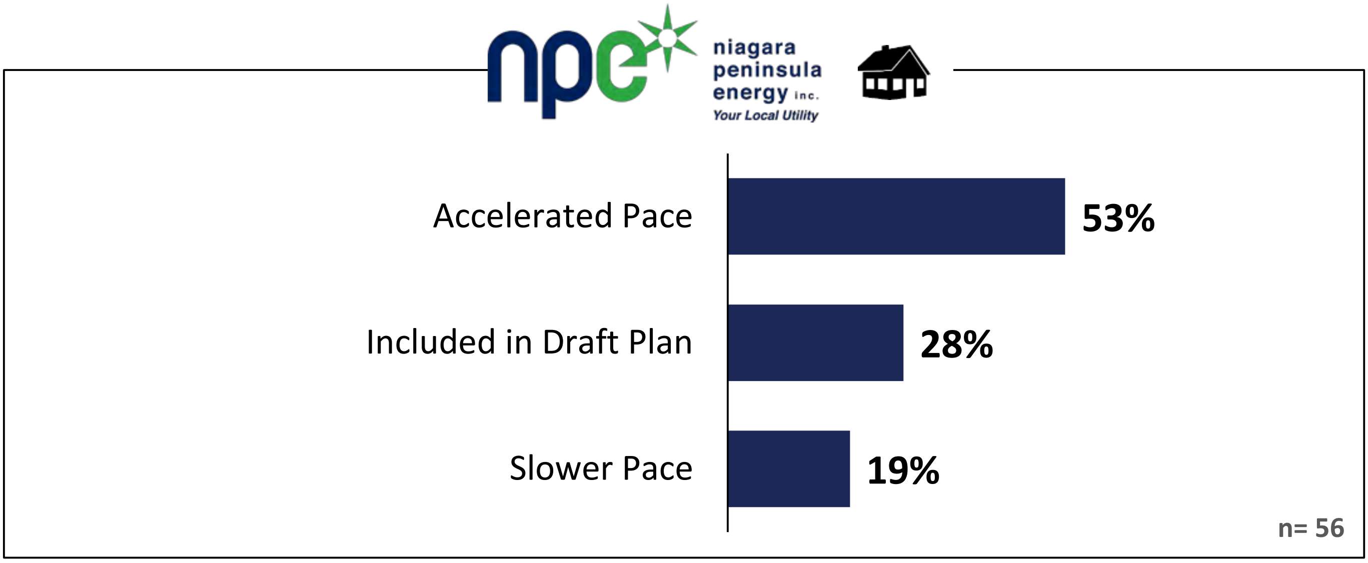
Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=7) 88% of respondents did not provide additional feedback	**n-size**
Replace within budget/find efficiencies/no increase to the consumer	3
Reliability/safety outweighs cost	1
Data/figures questionable	1
Cost acceptable/negligible	1
Be proactive/pay now to save later/costs will only increase	1

Representative Workbook

Background Information

Making Choices (3 of 7)

Converting Outdated Underground Kiosk Transformers

NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program has been pushed off, and today, there remains 75 transformers in need of replacement.

NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.

Option	Transformers Installed	Expected Outcome
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	55 by 2025 (11 per year)	Work towards eliminating all old installations over the next 7 years.
Reduced Pace ***Decrease*** *of $0.02 per month annually ($0.24 less per year)*	25 by 2025 (5 per year)	Work towards eliminating all old installations over the next 15 years.
Slower Pace ***Decrease*** *of $0.04 per month annually ($0.48 less per year)*	10 by 2025 (2 per year)	Work towards eliminating all old installations over the next 35 years.

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Converting Outdated Underground Kiosk Transformers

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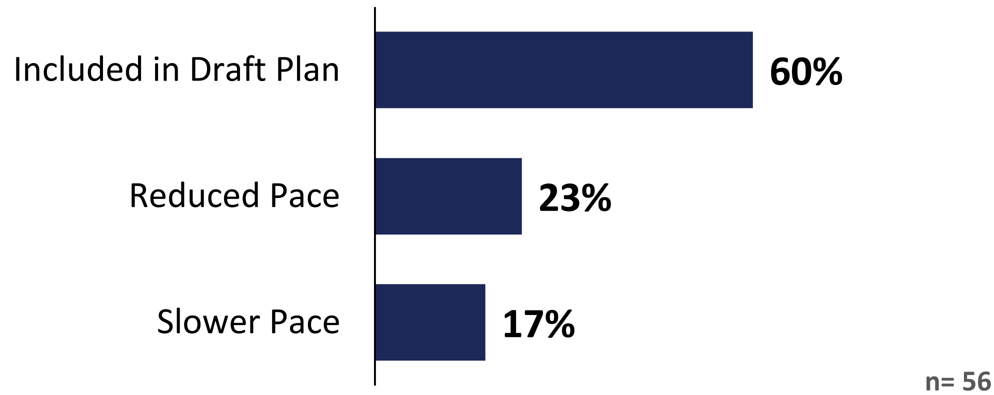
Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=5) 92% of respondents did not provide additional feedback	**n-size**
Replace as necessary/most urgent/outdated first/run to fail	2
Reliability/safety outweighs cost	1
Replace within budget/find efficiencies/no increase to the consumer	1
None	1

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Making Choices (4 of 7)

Underground cable replacement

Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years.

Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses.

Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.

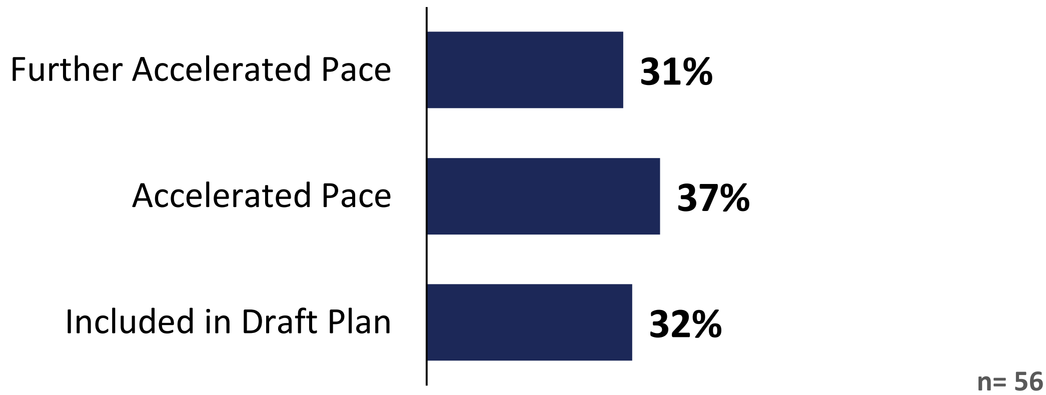
Option	**Km of cable installed**	**Expected Outcome**
Further Accelerated Pace ***Additional*** *$0.35 per month annually ($4.20 more per year)*	24 km by 2025 (4.8 km per year)	Proactively replace more of the cables identified as past end of life in the Asset Condition Assessment Report.
Accelerated Pace ***Additional*** *$0.07 per month annually ($0.84 more per year)*	12 km by 2025 (2.4 km per year)	Proactively replace some of the cables identified as past end of life in the Asset Condition Assessment Report.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	2 km by 2025 (0.4 km per year)	Replace cables past end of life as other work is being completed on associated switchgear or riser poles.

Representative Workbook

Underground cable replacement

Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=4) 93% of respondents did not provide additional feedback	**n-size**
Replace as necessary/most urgent first/if it isn't broke	2
Reliability/safety outweighs cost	1
Replace within budget/no increase to consumer/cash grab	1

Making Choices (5 of 7)

Subdivision underground rehabilitation

71 of the subdivisions in NPEI's service territory were constructed with **direct buried cable** which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier.

While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life.

In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs.

In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed.

Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time.

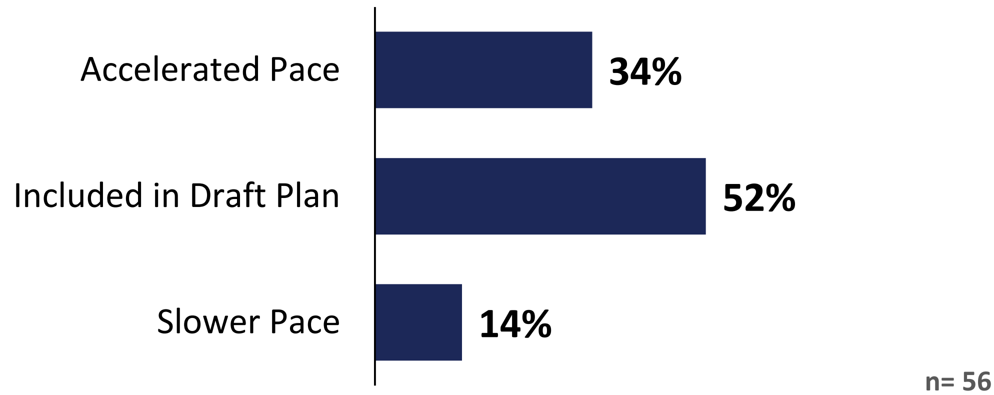
Between 2021 and 2025, NPEI is proposing a new program that will proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.

Option	Km of vault installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	30 km by 2025 (6 km per year)	Install 6 km of ducts or approximately four subdivisions per year.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	15 km by 2025 (3 km per year)	Install 3 km of ducts or approximately two subdivisions per year.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	7.5 km by 2025 (1.5 km per year)	Install 1.5 km of ducts or approximately one subdivision per year.

Representative Workbook

Subdivision underground rehabilitation

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=2) 96% of respondents did not provide additional feedback	**n-size**
Reliability/safety outweighs cost	1
Replace within budget/no increase to consumer	1

Making Choices (6 of 7)

Overhead rebuilds

Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system.

A recent asset health condition assessment identified a total of **60 areas** within NPEI's service territory that require complete overhead rebuilds**.** Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section.

This program is intended to contribute to the "betterment" of the overhead system by;

- Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and;
- Improving system aesthetics with new and taller poles.

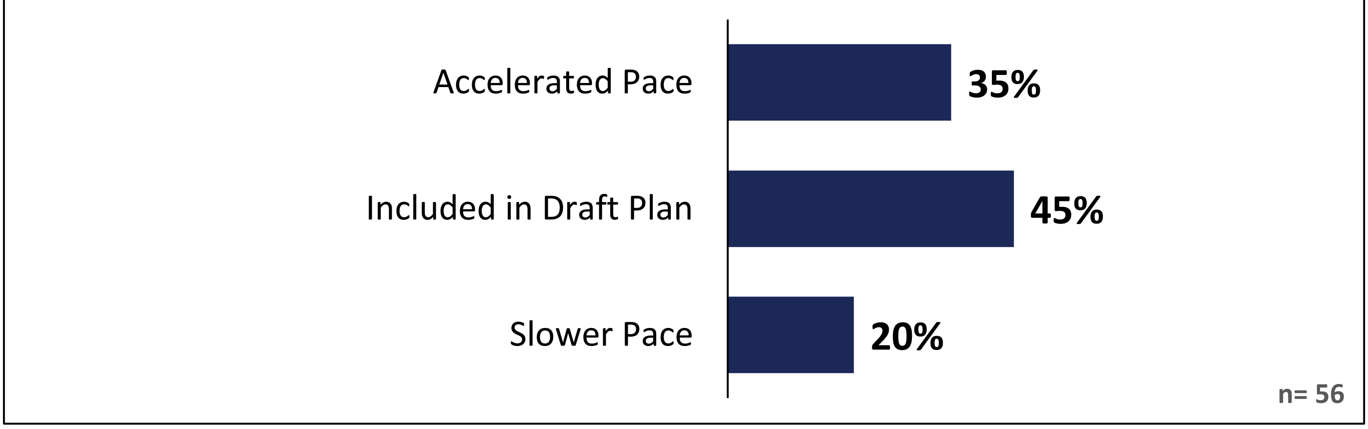
On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's current approach would rebuild **40 out of 60 areas** in the 2021 to 2025 period.

NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.

Option	Overhead rebuilds	Expected Outcome
Accelerated Pace ***Additional*** *$0.04 per month annually ($0.48 more per year)*	61 km by 2025 (12.2 km per year)	Rebuild 12.2 km per year or approximately 10 projects per year
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	48.5 km by 2025 (9.7 km per year)	Rebuild areas with assets that have been identified as very poor in Asset Condition Assessment. Rebuild 9.7 km per year or approximately 8 projects per year
Slower Pace ***Decrease*** *of $0.04 per month annually ($0.48 less per year)*	36 km by 2025 (7.2 km per year)	Rebuild 7.2 km per year or approximately 6 projects per year

Representative Workbook
Overhead rebuilds

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=2) 96% of respondents did not provide additional feedback	**n-size**
Reliability/safety outweighs cost	1
Replace within budget/find efficiencies/no increase to consumer	1

Making Choices (7 of 7)

Grid modernization

New technology has changed the way that NPEI can manage and monitor the distribution system.

Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory.

This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event.

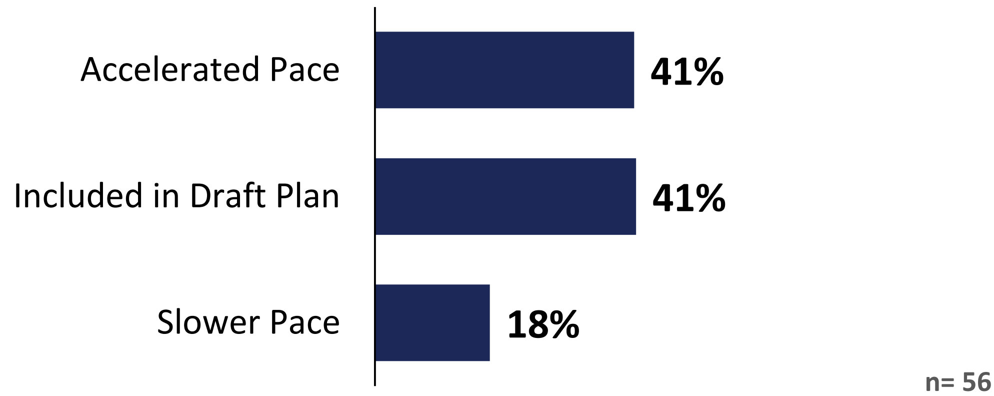
On average, since 2014, NPEI has installing approximately two remote devices per year, with focus on more rural, lower density areas. That said, there is an opportunity to install this monitoring and control equipment more quickly or slowly.

Option	Devices installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	20 devices (4 per year)	NPEI to double installation rate to four devices per year.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	10 Devices (2 per year)	Remain at current installation pace of two devices per year. Install new devices to expand NPEI's Smart Grid network. These devices provide better monitoring capability on the system, which leads to improved restoration times during outages.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	5 Devices (1 per year)	NPEI to cut rate of installation in half to one device per year.

Representative Workbook

Grid modernization

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=2) 96% of respondents did not provide additional feedback	**n-size**
Be proactive/pay now to save later/costs will only increase	1
None	1

Representative Workbook
Investment Alternative Summary

Impact of Choices

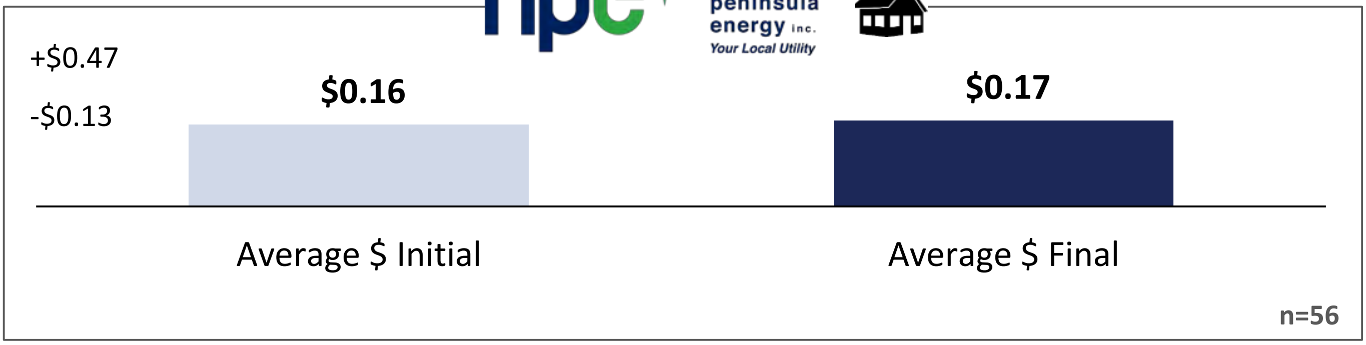
Investment Alternative Summary

Throughout this workbook, you have been asked about **seven key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page you will find the total bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential rate impact will be re-calculated. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Q Small Business Customer Bill Impact Change and Magnitude of Bill Impact (**MEAN**)



Differences that are statistically significant at 95% are noted by an asterisk (*).

Representative Workbook

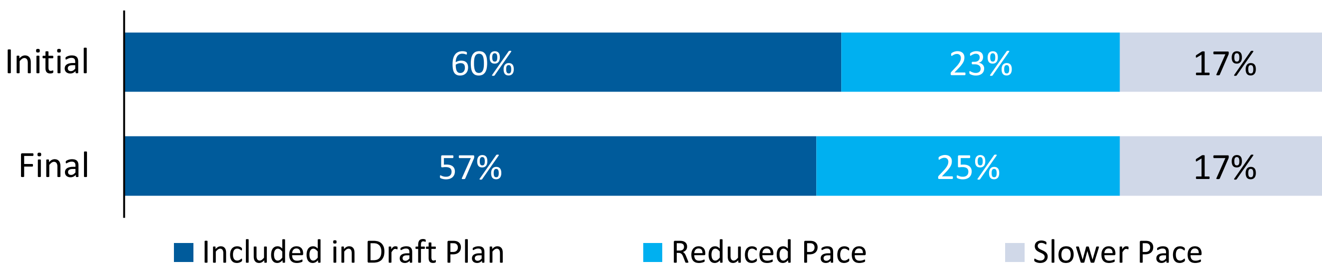
Change in Initial vs. Final Response by Project

Small Business

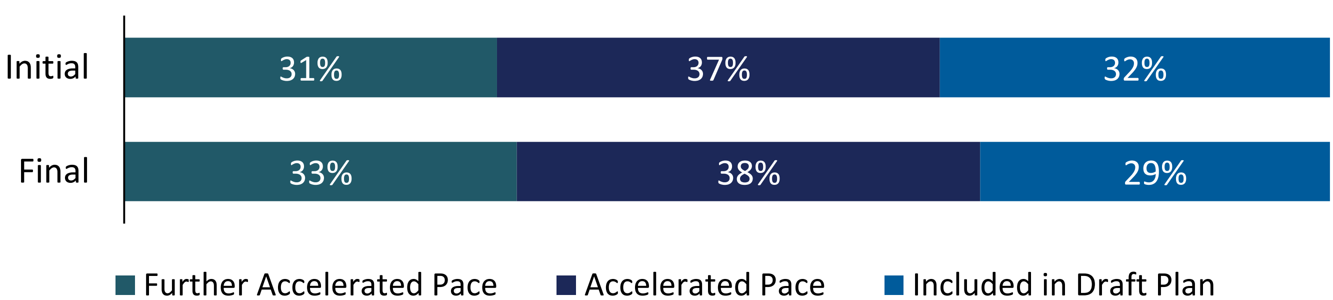
Q Overhead Pole Replacement

Q Overhead Transformer Replacement

Q Converting Outdated Underground Kiosk Transformers



Q Underground Cable Replacement



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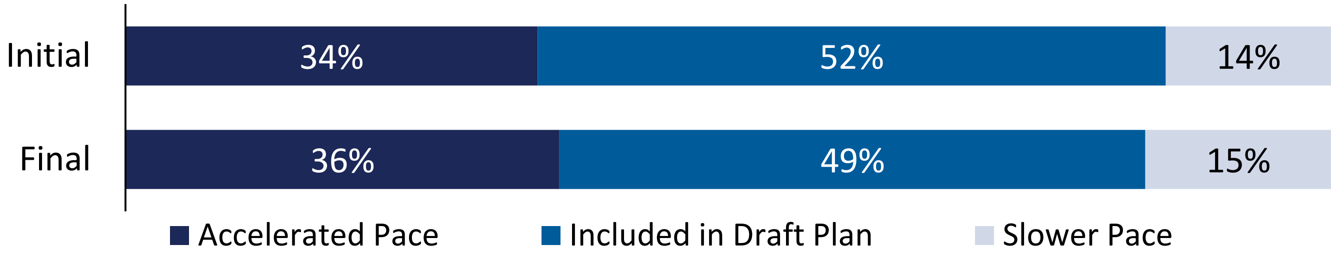
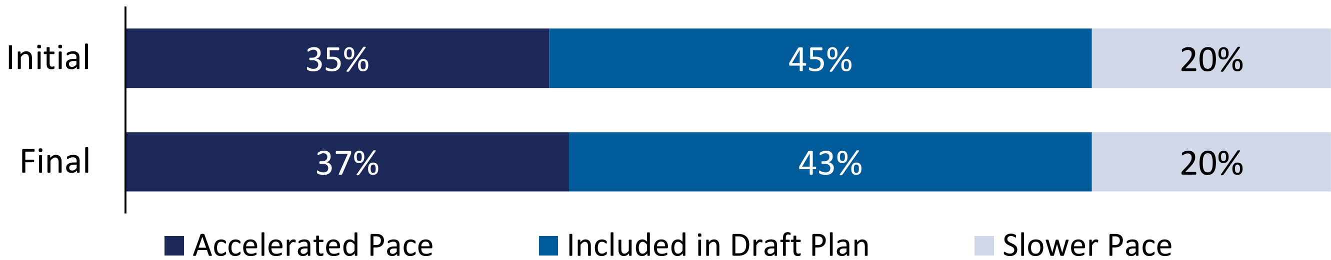
Small Business

Change in Initial vs. Final Response by Project

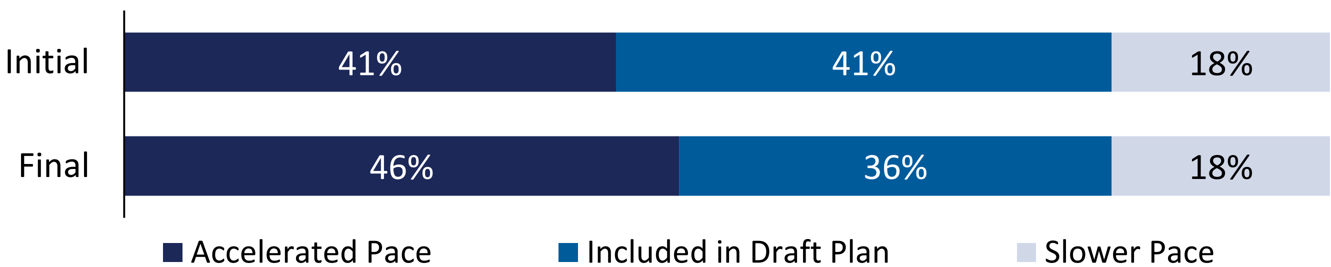
Q Subdivision Underground Rehabilitation



Q Overhead Rebuilds



Q Grid Modernization



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Impact of Choices

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Again, it is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $4.84 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical small business customer would see the distribution portion of their electricity bill increase by $8.46.
- As a result, the distribution charges on the typical small business customer's monthly bill would increase from $69.15 in 2020 to $77.61 by 2025.

Estimated Typical Small Business Annual Increase in Monthly Bill (5 year forecast)

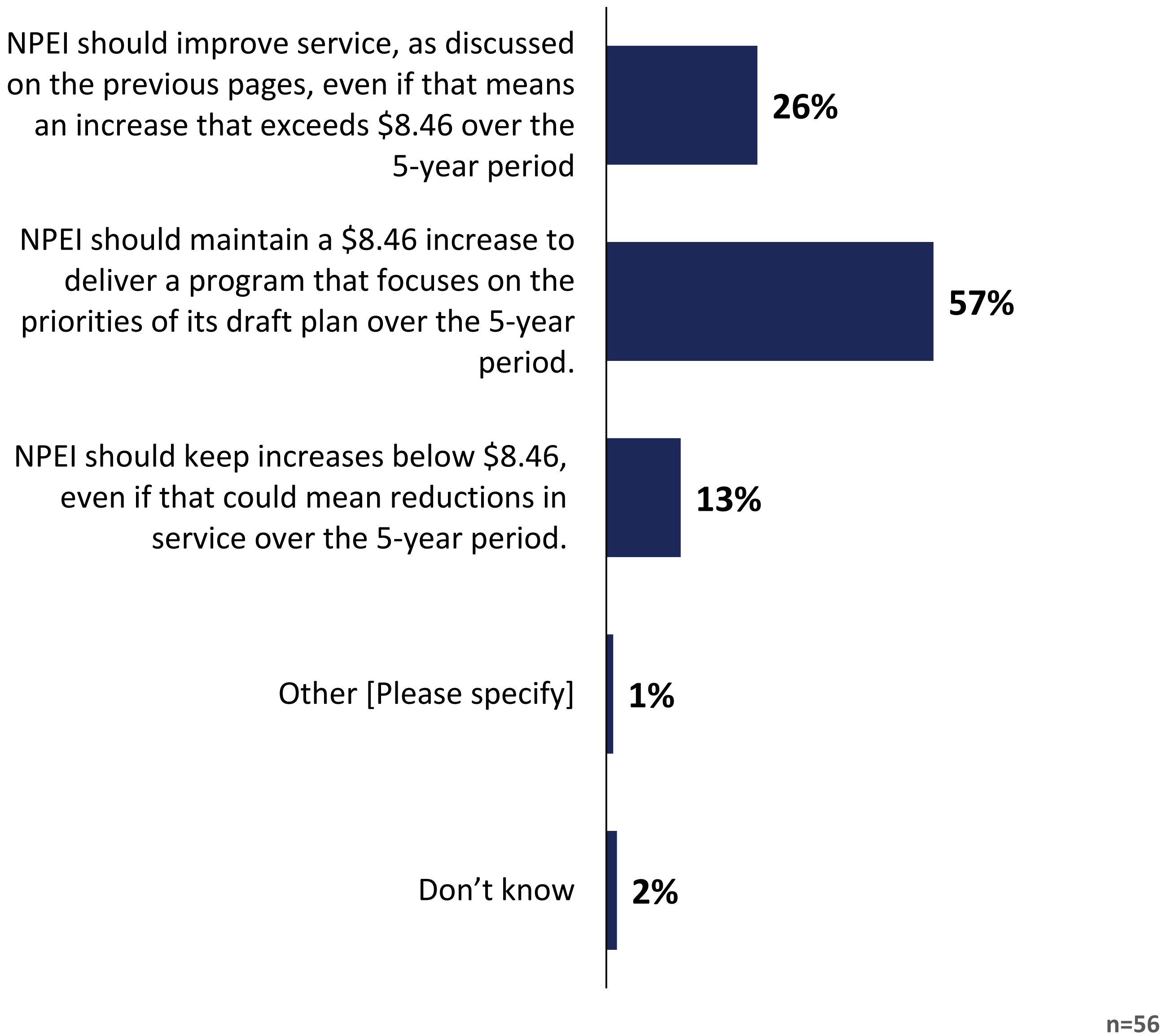
	Year	Average Small Business Bill	Distribution Portion of Bill	Incremental Rate Change	% Change * (on distribution portion of bill)
Current Rate	2019	$298.63	$68.28		
Budgeted Rate	2020	$303.11	$69.15	$0.87	1.27%
Forecast for next rate period	2021	$306.98	$73.99	$4.84	7.00%
	2022	$311.58	$74.88	$0.89	1.20%
	2023	$316.26	$75.78	$0.90	1.20%
	2024	$321.00	$76.69	$0.91	1.20%
	2025	$325.82	$77.61	$0.92	1.20%
				$8.46	

*** These estimates are preliminary, and are subject to your feedback as the business plan is finalized .**

Representative Workbook

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Q Considering what you know about Niagara Peninsula Energy's draft plan – which would see the typical small business customer's distribution portion of their bill increase by $8.46 over the 5-year period – which of the following best represents your point of view?



Representative Workbook

Final Comments

Q Thinking about your answer to the previous question, why do you feel that NPEI should take that approach over the 2021-2025 period?

Final Comments (n=20) 64% of respondents did not provide additional feedback	**%**
Proactive approach-Pay now to ensure proper maintenance and prevent higher cost in the future	9
Increase is reasonable -taking affordability into account	8
Rates are high enough already/no increase	3
None	1

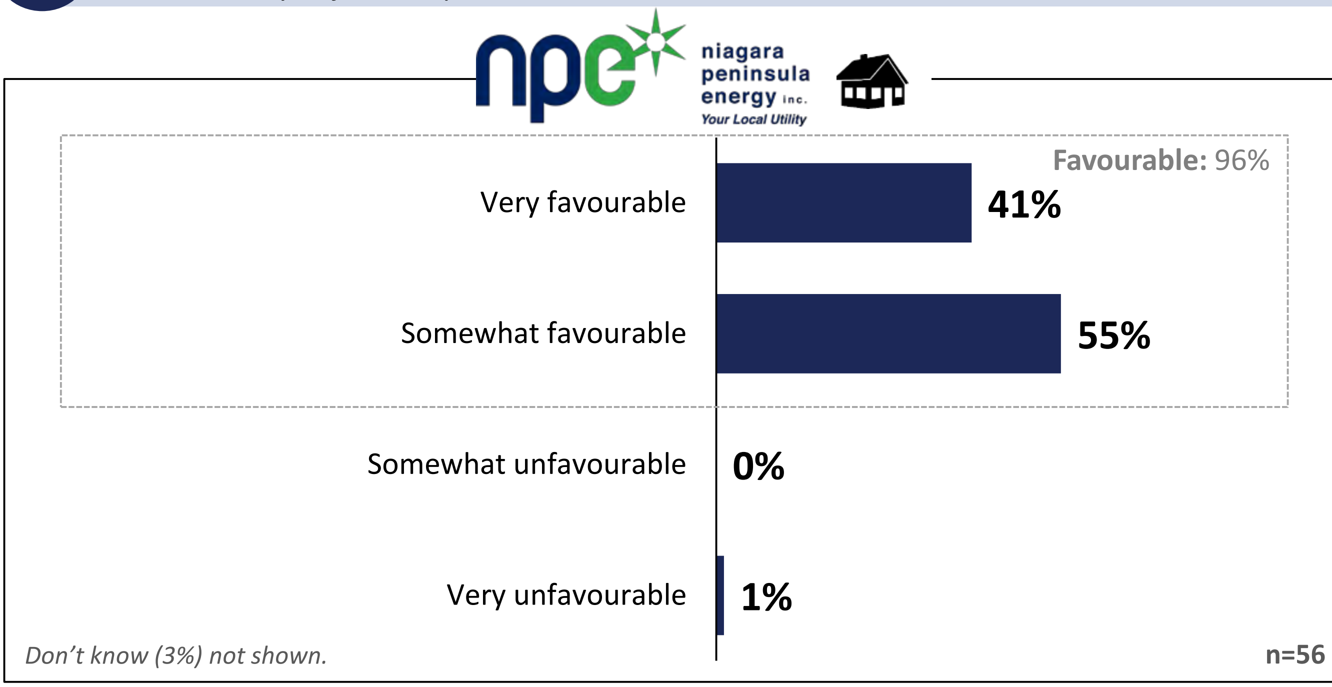
Q Do you have any final comments regarding NPEI or the customer engagement that you just completed?

Final Comments (n=10) 82% of respondents did not provide additional feedback	**%**
Positive - General NPEI/Survey/ asking for Customer input/informative	4
Invest now to avoid higher cost in the future/Maintain and repair accordingly	3
Cost issues/delivery fees/High rates/keep cost low	2
None	1

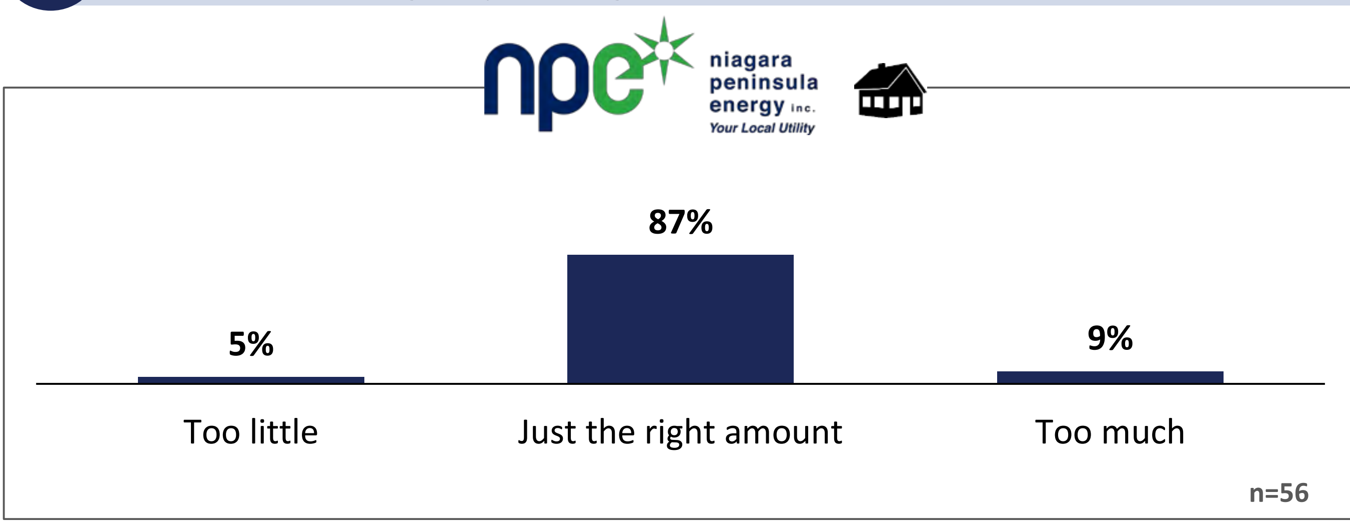
Representative Workbook

Final Thoughts: Workbook Diagnostics

Q **Overall Impression**: Overall, did you have a favourable or unfavourable impression of the consultation you just completed?



Q **Volume of Information:** In this consultation, do you feel that NPEI provided too much information, not enough, or just the right amount?



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Content Covered and Unanswered Questions

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Q Was there any content missing that you would have liked to have seen included in this consultation?

Content Covered (n=56)	%
None	50
Cost/delivery fees/High rates/keep cost low	2
More information on system reliability aging infrastructure/preventative measures	1
Billing issues/clearer breakdown/electronic	1
Other	3

Q Is there anything that you would still like answered?

Unanswered Questions (n=56)	%
None	50
Transparency-Cost allocation	2
Going underground/transformers/lines	1
Consultations with Customers/ updates as to what course of action and plan will be taken	1
Cost issues/delivery fees/High rates/keep cost low	1
Positive - General NPEI/Survey/ asking for Customer input/informative	1

INNOVATIVE
RESEARCH GROUP

Commercial (GS > 50 kW) Customers

Online Workbook Results

INNOVATIVE was engaged by NPEI to gather input among commercial (GS > 50 kW) customers on preferences on program timing and balancing outcomes. **Pages 115 to 157** show the actual pages of the workbook that was sent and completed by customers. The only additions are the actual results.

Field Dates & Workbook Delivery

The **Commercial Online Workbook** was sent to all NPEI GS > 50 kW customers who have provided the utility with an email address. Customers had an opportunity to complete the workbook between **December 3rd and December 18th, 2019**.

Beyond the initial invite on **December 3rd**, customers were sent multiple reminder emails to encourage participation. Additionally, NPEI staff placed follow-up telephone calls to encourage participation.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the workbook was sent to **447 GS > 50 kW** customers via e-blast from INNOVATIVE.

Commercial (GS > 50 kW) Online Workbook Completes

A total of **32** (unweighted) NPEI GS > 50 kW customers completed the online workbook via a unique URL.

Individual GS > 50 kW customer responses were anonymous and no identifiable respondent information was shared with NPEI. Responses were combined to protect the confidentiality of individual customers.

Sample Distribution

Due to sample size this data has not been weighted, and is presented in n-sizes rather than percentages. Results should be treated as directional only.

Eligible Sample (Accounts with email addresses)	Completed Workbooks	% of Completed Workbooks vs. Eligible Sample
447	32	7.2%

Total Sample (Unique accounts)	Approximate # of unique accounts represented*	% of Unique Accounts Represented vs. Total Sample
781	74	9.5%

* Based on an analysis of the "total" sample, the 32 completed workbooks represent approximately 74 unique GS > 50 kW accounts or 9.5% of the total sample pool of 781 GS > 50 kW customers.

Representative Workbook

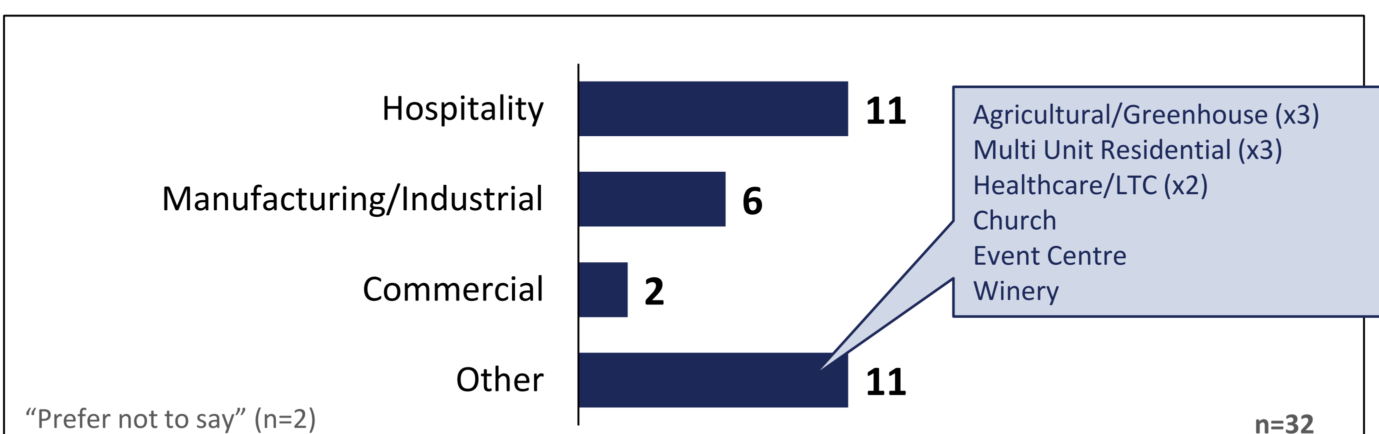
Demographic Breakdown

Commercial
GS > 50 kW

Q Company Size

Q Responsibility for Managing or Overseeing Organization's Hydro Bill

Q Sector



INNOVATIVE RESEARCH GROUP

Representative Workbook

Environmental Controls

Niagara Peninsula Energy Inc.
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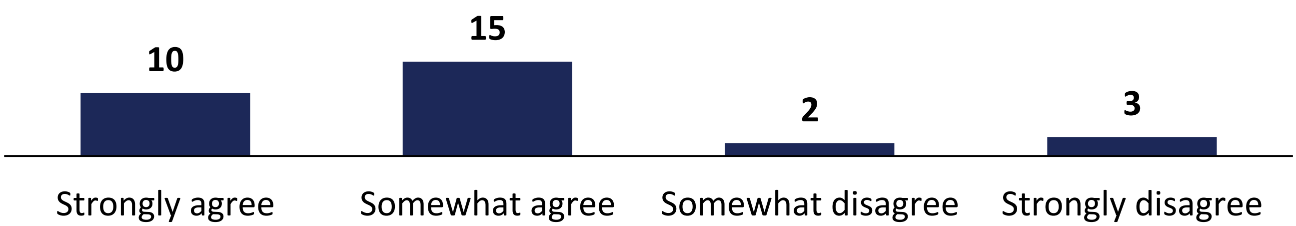
Thinking generally about the electricity system in Ontario, including generation, transmission and local distribution, do you agree or disagree with the following statements?

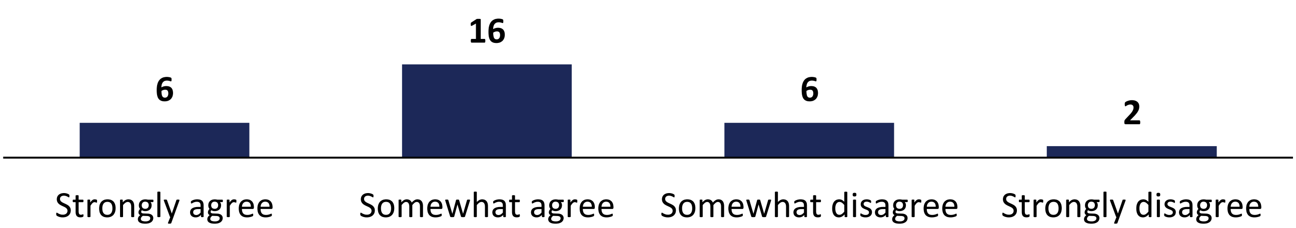
Q The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know" (n=2) not shown.

n=32

Q Customers are well served by the electricity system in Ontario.



"Don't know" (n=2) not shown.

n=32

About this Consultation

Welcome to Niagara Peninsula Energy's Customer Engagement!

Niagara Peninsula Energy (NPEI) needs your input on choices that will impact the services you receive and the rates that you pay.

- **NPEI** is developing its investment plan for 2021 to 2025. This plan will determine the investments NPEI will make in equipment and infrastructure; the services it provides; and the rates you pay.
- As **NPEI** plans for the future, they want to ensure their business decisions are aligned with customers priorities, preferences, and needs.
- Throughout this survey, information will be provided in an effort to give you more background on which to base your responses.
- While responding to the following questions, remember that there are no wrong answers, and that your individual responses will remain anonymous.
- This customer engagement will take approximately 25-35 minutes to complete, depending on the level of feedback you wish to provide. Your progress will be saved as you move through the workbook, meaning you can leave and return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired NPEI to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one (1) $500 cash prize.

If you are reading this on a smaller mobile device, you may want to consider accessing the survey from a tablet, desktop or laptop instead so that it is easier for you to read.

Please note that the estimates throughout are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.

For the purpose of this exercise, the estimates are based on a customer with a monthly demand of 180 kW and monthly consumption of 65,000 kWh.

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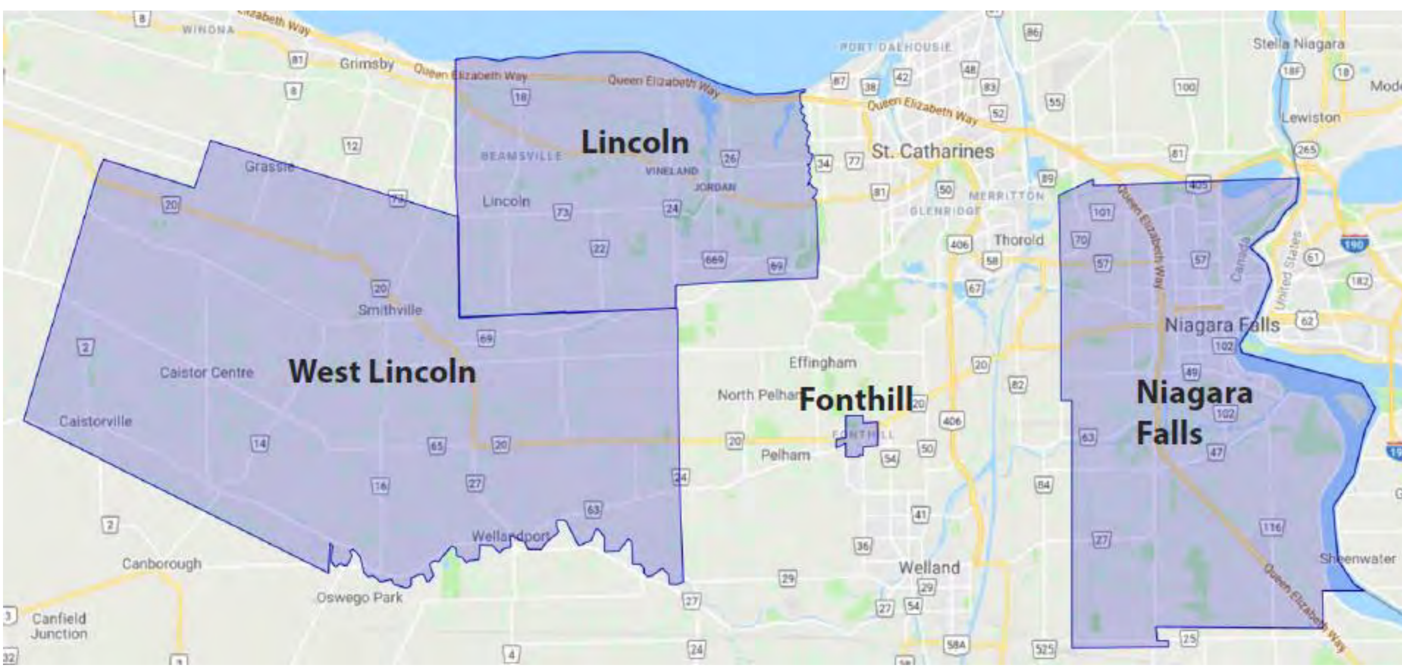
Electricity 101

Who is Niagara Peninsula Energy?

NPEI provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham, and Township of West Lincoln.

- NPEI serves an area of approximately 827 square kilometers and a customer base of approximately 55,600 residential and business customers, containing a mix of urban and rural electrical distribution.
- NPEI is jointly owned by the municipalities it services.
- NPEI manages all aspects of the electricity distribution business and is regulated by the Ontario Energy Board (OEB).
- As a local distribution company (LDC) and regulated entity, NPEI applies for, and receives approval from the regulator to charge for its services.



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Electricity 101

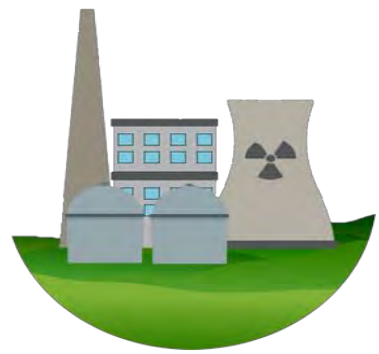
Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

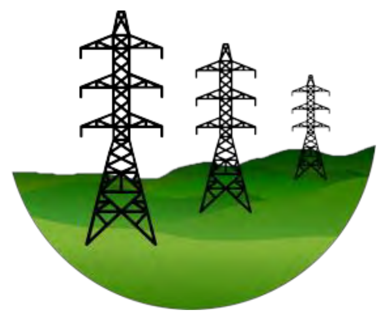
Ontario's electricity is generated using a mix of nuclear, gas-fired, and water power (hydro), as well as biomass and renewable sources such as wind and solar technology. In Ontario, a number of companies own these generating stations but approximately half of the electricity is generated by Ontario Power Generation. The Independent Electricity System Operator (IESO) balances the supply of, and demand for, electricity on a second-by-second basis and directs its flow across the high-voltage transmission lines.



Transmission

How electricity travels across Ontario

Once generated, electricity must be transported to electrical substations across the province. Due to the large amount of power and long distances, transmission normally takes place at high voltages with the lines suspended on large, steel towers. The province has more than 30,000 kilometres of 'electricity highway', most of which is owned and operated by Hydro One.



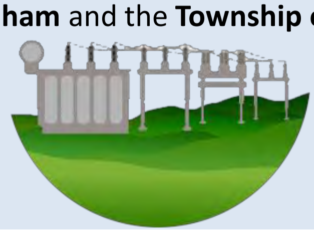
Local Distribution

How electricity is delivered to the end-consumer

NPEI is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, NPEI delivers electricity to approximately 55,600 residential and business customers.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.



npe niagara peninsula energy Inc. Your Local Utility

Representative Workbook

Familiarity with Ontario’s electricity system

Commercial
GS > 50 kW

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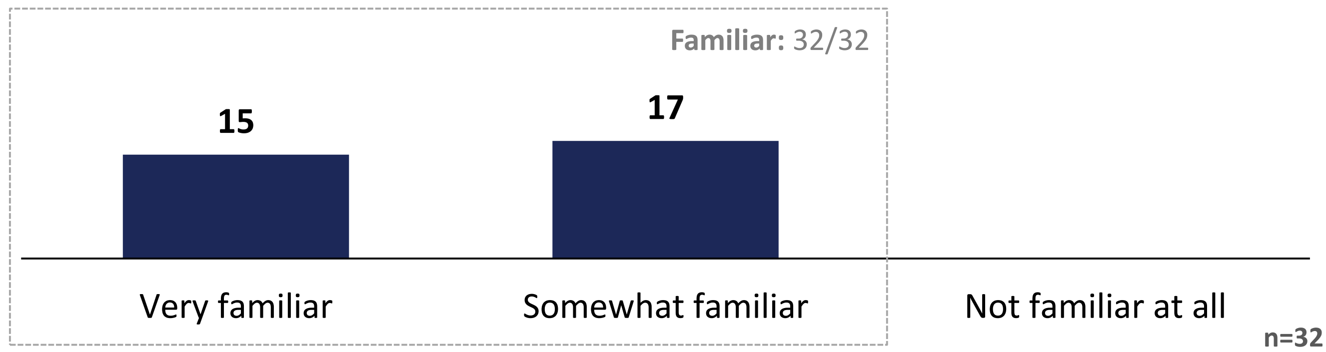
Q Before this survey, how familiar were you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?



Representative Workbook

Background Information

Electricity 101

How much of my electricity bill goes to Niagara Peninsula Energy?

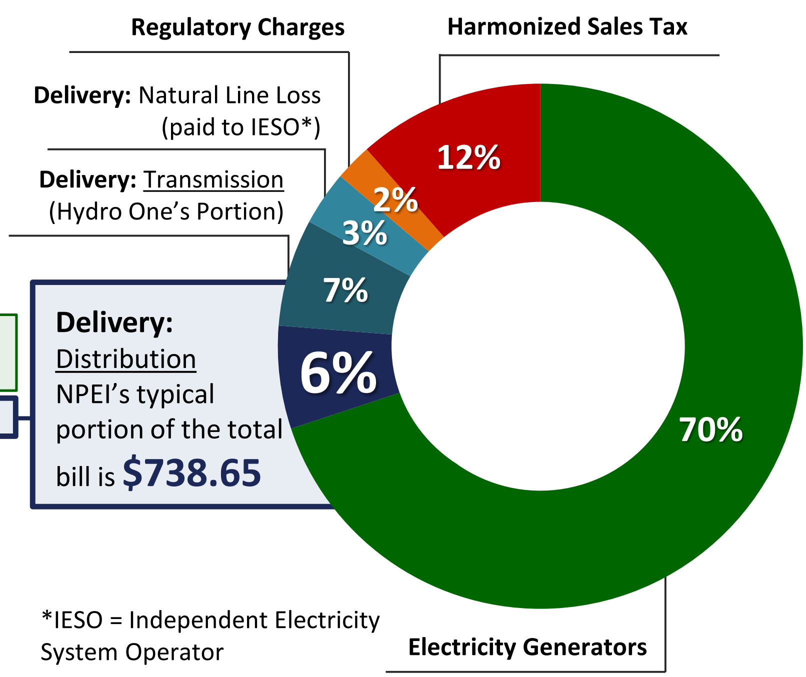
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge.
- Distribution makes up about **6%** of the typical mid-sized business customer's bill.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

NPEI Sample Monthly Bill*
(Based on 180 kW Monthly Demand)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Electricity Charge	1,202.50
Global Adjustment	6,951.10
Delivery	1,900.21
Regulatory Charges	265.89
Total Electricity Charges	**$10,319.71**
HST	1,341.56
Total Amount	**$11,661.27**



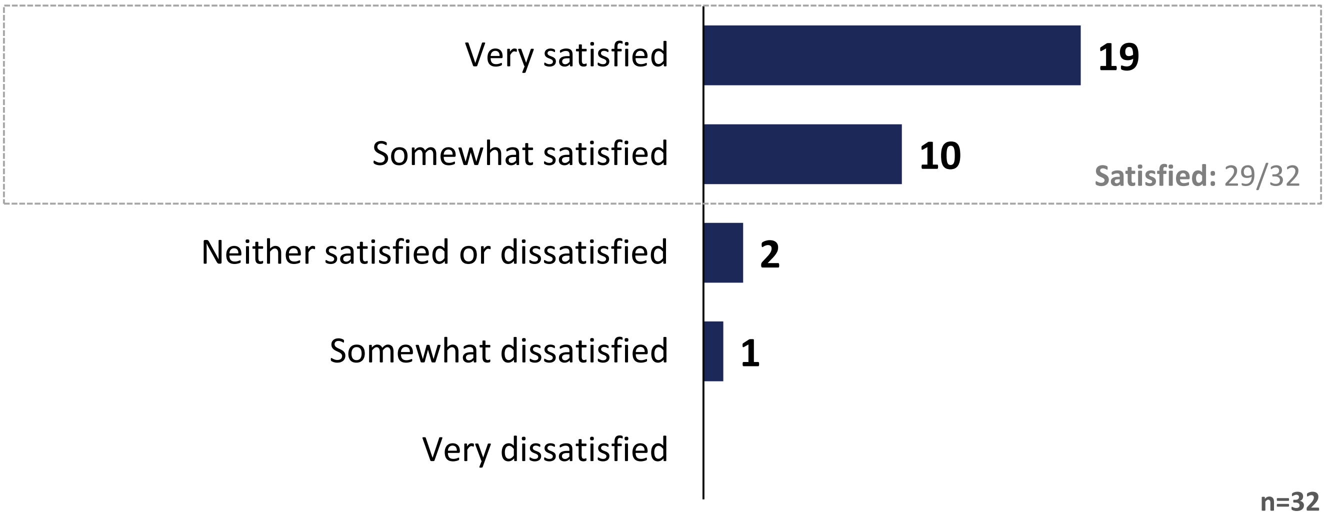
*IESO = Independent Electricity System Operator

* As of November 1, 2019. Based on typical monthly consumption of 65,000 kWh

Representative Workbook

Overall Satisfaction with Niagara Peninsula Energy

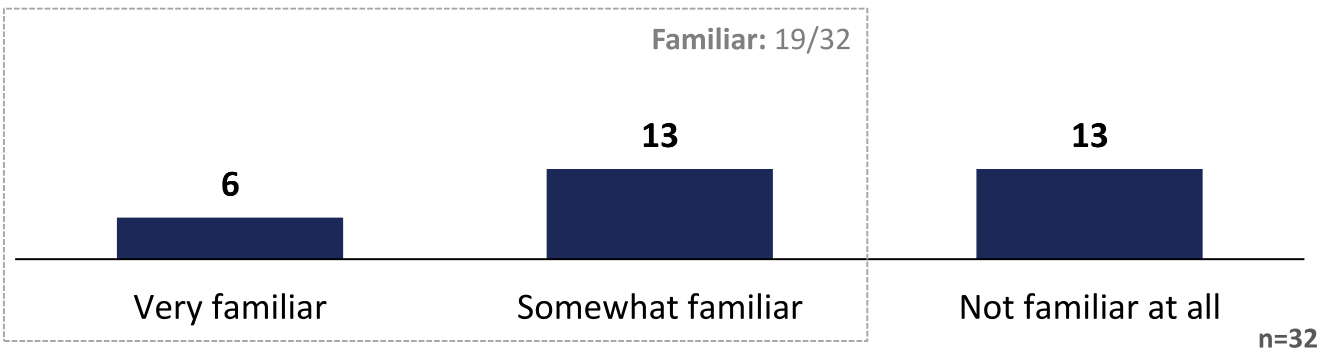
Q Thinking specifically about the services provided to you and your community by Niagara Peninsula Energy, overall, how satisfied or dissatisfied are you with the services that your organization receive?



Representative Workbook

Familiarity with Percentage if Bill Remitted to NPEI

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Niagara Peninsula Energy?



Q Is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to your organization?

Improving Services (n=6) Verbatim Responses 26/32 of respondents did not provide additional feedback
As a long-term care facility with 231 residents, we rely on a reliable source of electricity, and while we have a generator backup that powers some of our equipment, power outages do cause some issues with the our building systems and computer equipment. We understand that power outages beyond your control do occur, but any tree trimming near hydro lines helps reduce risk.
I would like them to continue doing the retro fit LED program.
Ignoring our "battle" at minimizing the global adjustment which is our main issue I would like our monthly invoices to reach is much sooner than they do now. This is obviously for financial statement purposes.
More Education to their customers.
Ontario electricity rates are too high compared to other provinces. Especially in the Niagara Region where we can generate hydro electric power
The delivery charge on our bill is closer to 50% of the final bill... we have queried this in the past without any success.

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Niagara Peninsula Energy Background

Building Niagara Peninsula Energy's draft plan

NPEI has put together its draft business plan based on the information and input from various sources, such as:

- **Legal and regulatory** requirements by continuing to meet its obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected through both ongoing dialogues and specific engagements, such as this.

There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their businesses and serve their customers.

- **Policy**: The Ontario Ministry of Energy, Northern Development and Mines (MNDM) creates energy policy for the province.
- **Regulation**: The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.
- **Operations and Planning**: The Independent Electricity System Operator (IESO) manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

Ontario ENERGY /ÉNERGIE

ONTARIO ENERGY BOARD

ieso Connecting Today. Powering Tomorrow.

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Niagara Peninsula Energy Background

How did customer feedback shape Niagara Peninsula Energy's draft plan?

NPEI is placing more emphasis on incorporating customer feedback into the planning process than ever before.

NPEI engages with its customers both in day-to-day interactions and in a variety of customer engagement activities. These interactions help identify customer needs and preferences, and inform how the utility plans for the future.

This past summer, NPEI engaged with **thousands of residential and business customers** from across its service territory – both in person and through telephone and online surveys.

What did NPEI hear from customers like yourself?

1. The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates".

2. Among competing outcomes, **price**, **reliability**, and **finding internal cost efficiencies** are the top three priorities for both residential and small business customers.

3. While keeping price at a reasonable and affordable level is an important priority, many customers feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Considering this feedback, as well as the information and inputs discussed on the previous page, NPEI has developed a draft plan that is responsive to:

1. Legal requirements by continuing to meet its obligations, including safety and reliability;

2. A transformer station upgrade to accommodate the new Niagara South Hospital and future surrounding growth.

3. Mandatory service connections to accommodate new customers and customer-required upgrades, of which NPEI does not have control over how and when these costs are incurred.

4. Customer feedback by:

    a) Keeping distribution price increases as low as possible;

    b) Maintaining long-term performance for customers experiencing average or better service;

    c) Improving service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,

    d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

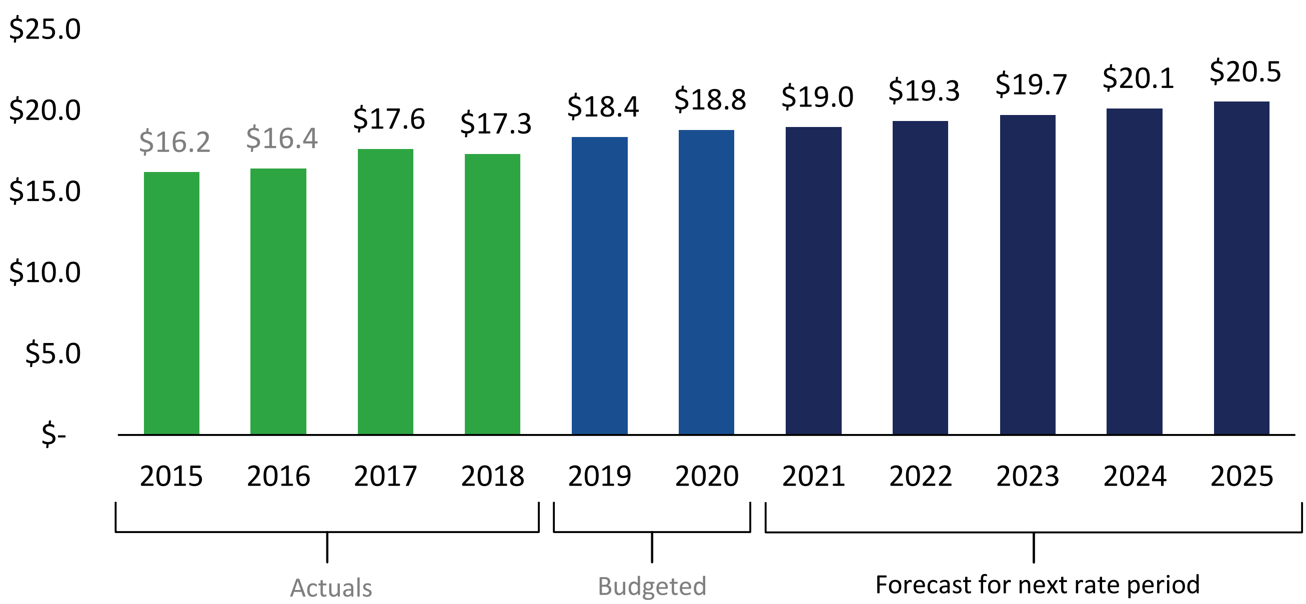
Niagara Peninsula Energy Background

Operating Expenses

In this section, we want to focus on operating expenses and how NPEI compares to its peers.

NPEI's operating budget covers recurring expenses, such as the maintenance of poles, wires, transformers, fleet and buildings as well as proactive maintenance programs such as tree trimming, and payroll for employees. Meter reading, postage, cyber security and hardware/software maintenance expenses are billing and customer service-related expenses. The proposed 5-year plan, between 2021 and 2025, would see NPEI spend an estimated total of $98.7 million on operations.

NPEI's Current and Forecasted Operating Expenses, per Year (Millions)*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

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NPEI's **operating costs** are benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, NPEI's operating costs per customer was **$311.67**, which is slightly more than some, while less than both Hydro One and Canadian Niagara Power.

2018 Operating & Maintenance and Administration (OM&A) Per Customer ($)

The diverse geographical nature of NPEI's service territory, which is a mix of urban and rural communities is a large consideration/driver of these OM&A costs. In some parts of the service territory, there may be less than 30 customers per kilometer of line. Despite low density, these lines still require the same level of ongoing maintenance, including tree trimming and other expenses that contribute to operating the system; thereby resulting in a higher cost per customer.

Niagara Peninsula Energy Background

Operating Expenses

Recall, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge NPEI's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found at oeb.ca/participate.

This customer engagement however, is focused on capital investments.

Detailed discussion of NPEI's operating budget is left to experts from the OEB and intervenors in the formal rate application review; this workbook focuses on collecting your view on competing trade-offs in capital investments.

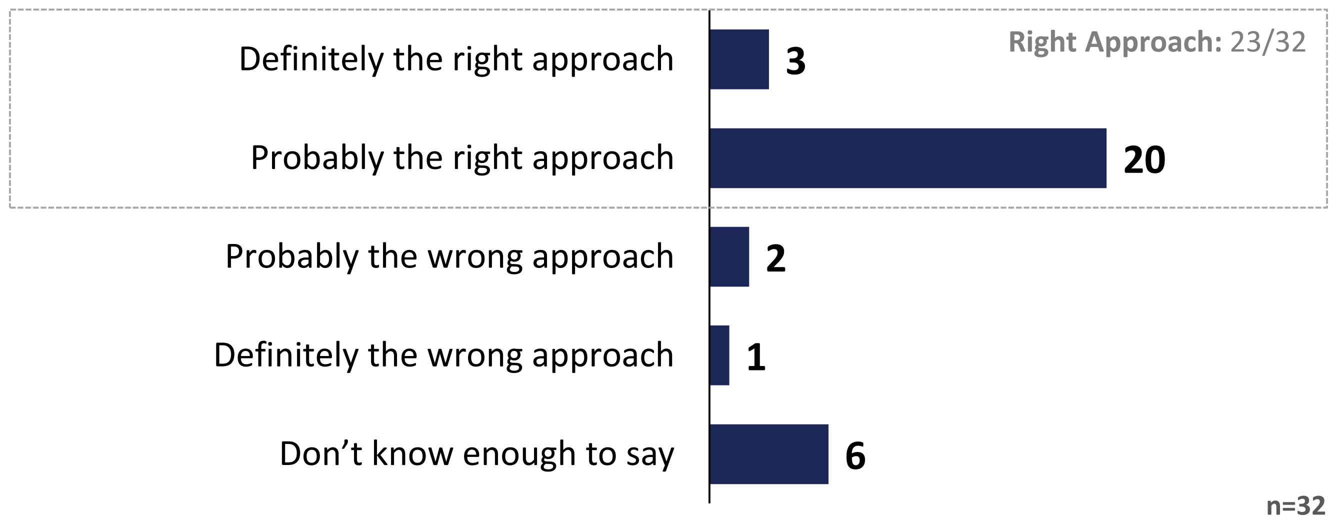
Representative Workbook

Approach to Operating Expenses

Commercial
GS > 50 kW

Q Does leaving the detailed discussion about Niagara Peninsula Energy's operating budget to experts from the OEB and intervenors seem like the right approach or wrong approach to you?

niagara peninsula energy inc. *Your Local Utility*



And why do you leaving the detailed discussion about NPEI's operating budget to the OEB and intervenors is the wrong approach? Amongst those who say "wrong approach", n=3
NPEI knows their business better than anyone
I don't trust the OEB to make the best decisions
I think from our information we receive from our local hydro NPEI, that the Ontario Energy Board is their regulator who should only oversee, I want to know how much does it cost NPEI to do these every 5 years to the OEB and Why do we need extra intervenors who are probably paid lobbyists for specific sectors. Listen to the customers NOT paid lobbyists which NPEI surveys us anyways.

INNOVATIVE RESEARCH GROUP

Representative Workbook
Background Information

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Niagara Peninsula Energy Background

Capital Investments

NPEI's **capital budget** covers items that, once purchased, have lasting benefits over many years. Year-over-year, regardless of external drivers, NPEI will need to make investments in the core distribution system, including poles, wires, cables and transformers.

Based on initial customer input and the approach outlined previously, NPEI believes the capital expenditure required to address system renewal, maintain system reliability and safety, and invest in other infrastructure priorities between 2021 and 2025 is estimated to be **$70.3 million**.

NPEI classifies the costs of four types of capital investment between 2021 and 2025. Each of these four investment categories helps NPEI pace and prioritize projects.

2021-2025 Forecasted Capital Investments

System Renewal ($38.2 million)

These projects are a mix of planned end-of-life replacements and emergency replacements.

Projects Include: Replacement of existing overhead wires, poles, and pole mounted transformers, underground cables and transformers and transformer station upgrades.

System Access ($17.1 million)

"Must do" investments that respond to customer requests for new connections or new infrastructure development.

Projects Include: NPEI's share of new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs.

General Plant ($8.4 million)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

Projects Include: Financial and customer IT systems, enhanced cyber security investments, facility renovations, backup generation, and vehicle replacements.

System Service ($6.6 million)

These investments consist of projects that address capacity constraints, improve system reliability and customer service.

Projects Include: Installation of automated switches and system expansion to supply new development.

Niagara Peninsula Energy Background

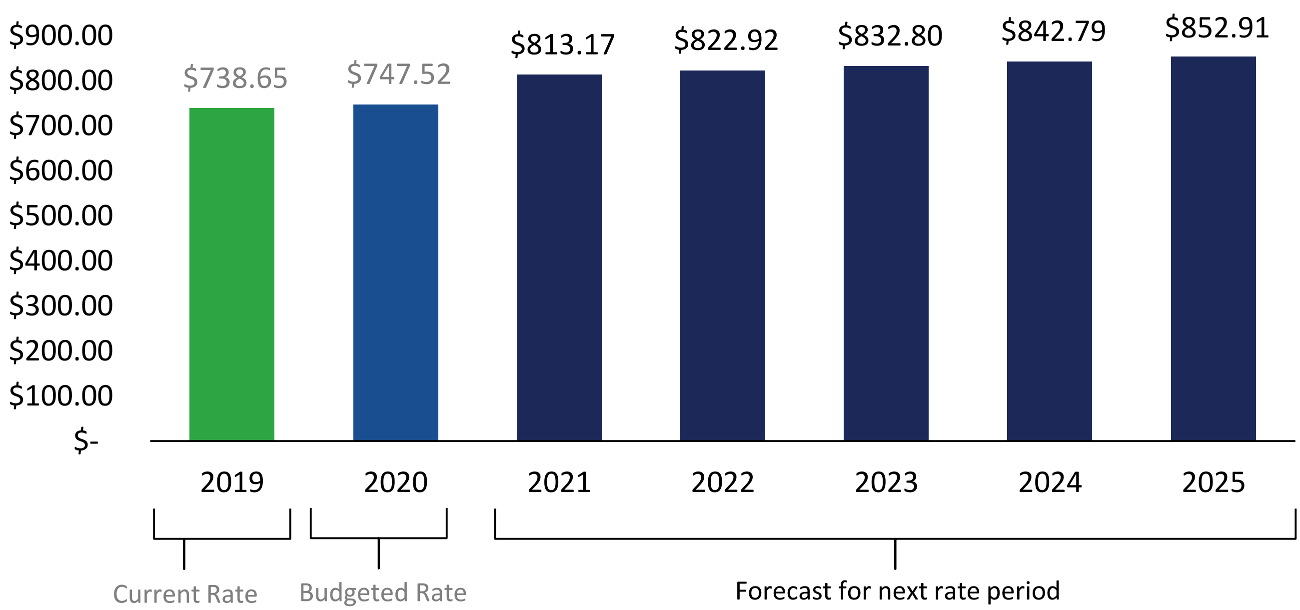
How much will this draft plan cost me?

Remember, the current typical NPEI mid-sized business customer's electricity bill is about $11,600 per month, of which $738.65 goes to NPEI.

It is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $65.65 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical mid-sized business customer would see the distribution portion of their electricity bill increase by $105.39.
- As a result, the distribution charges on the typical mid-sized business customer's monthly bill would increase from $747.52 in 2020 to $852.91 by 2025.

Estimated Mid-Sized Business Monthly Distribution Charge, per Year*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI is looking for your input on its preliminary plan to ensure it is making the spending decisions that matter to you, the customer.

The following sections of this workbook will explore some of the choices Niagara Peninsula Energy needs to make to help finalize its preliminary plan.

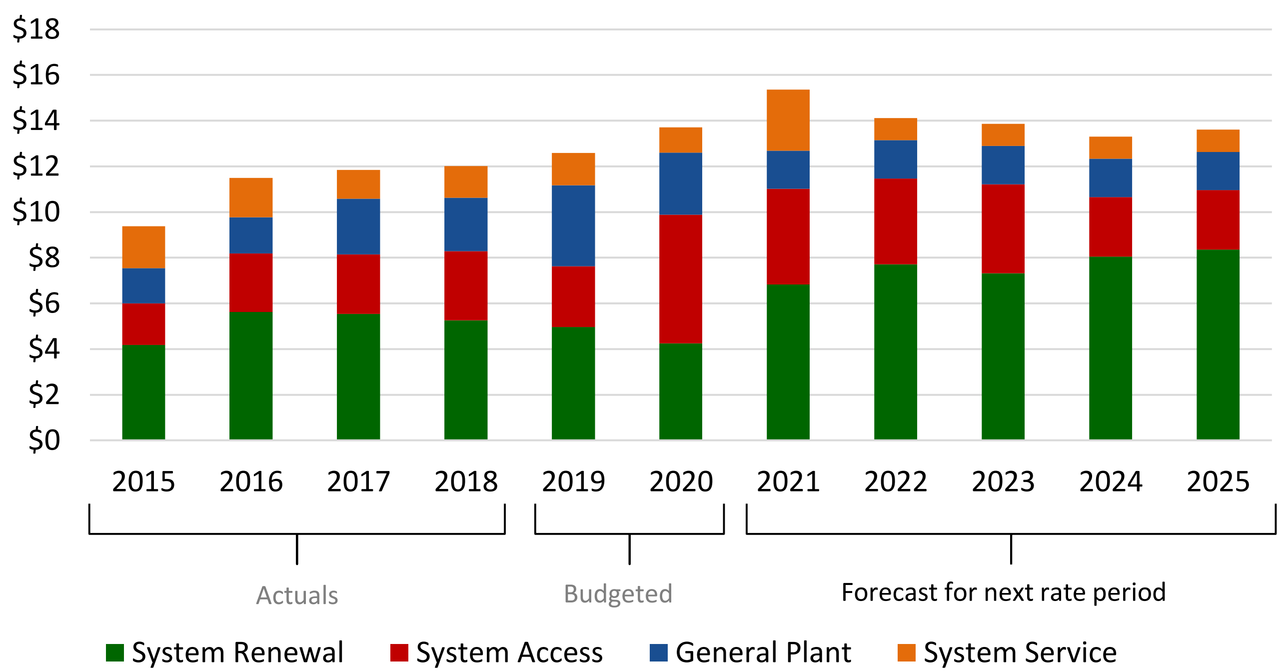
Niagara Peninsula Energy Background

Pacing Capital Investments

The overall amount NPEI invests in capital projects remains generally the same year over year, but what does change is where these investments are made. In some years, when unplanned or unforeseen investments are needed, NPEI will re-allocate funds to make room for these projects within the approved budget. This helps limit the overall amount that the distribution charges fluctuate year-over-year.

The chart below outlines NPEI's spending in past years, and proposed spending for the 5-year period 2021 to 2025.

2015 – 2025 Historical and Forecasted Capital Investments*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

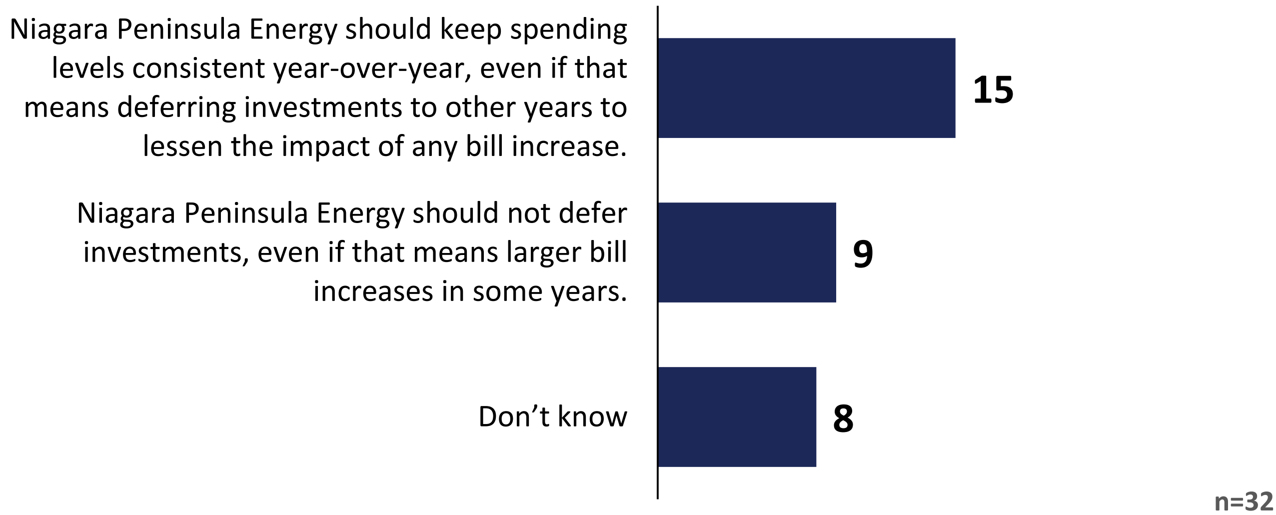
System Access expenditures are budgeted to increase to $5.6M in 2020 to accommodate a number of large commercial customer growth projects as well as municipal road work.

Representative Workbook

Approach to Pacing Investments

Commercial
GS > 50 kW

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to pacing investments?



Q Additional Feedback (Optional)

Additional Feedback (n=6) Verbatim Responses 26/32 of respondents did not provide additional feedback
Again, review your billings the amount you are getting is not 6% it is ten times higher.
And like every successful business watching the pennies helps watch the dollars try not to spend frivolously money that isn't yours
Any of this should be decided on a ROI basis.
As a business you need to invest as infrastructure over years needs to upgraded to keep to a standard level, however, keeping in mind weather incidents are occurring more frequently therefore investing in infrastructure, poles & wires and upcoming renewables that will be more important in the future - Storage, micro grids, renewables. Hydro is an ESSENTIAL service to our business operations.
Due to the ever increasing cost of hydro within the province they need to minimize price increases until as such time the debt is lowered thus paying less interest on the debt whereas they can than slowly start to increase prices slowly to increase their budget to allow them what they need to do. We are paying far too much for hydro in this area.
The options provided are too simplistic. A case by case decision should be applied but in general I would support not deferring investments if in the long-term these investments would be beneficial

Niagara Peninsula Energy Background

Mandatory Investments

Federal, provincial, and municipal governments as well as regulators set requirements and standards that NPEI must satisfy. Mandatory investments can be broken down into three categories:

- **Connecting customers**: This includes connecting customers to the grid when a new home or building is constructed or modified.
- **Moving equipment**: This includes moving equipment like poles and cables for road widening.
- **Mandated obligations**: This includes installing and maintaining customer meters and transferring electricity from the provincial transmission system.

These mandatory investments mean that about **one-in-four dollars (23%)** of your distribution rates over the past five years have not been available for other non-mandatory investments. Looking forward to the 2021-2025 period, NPEI forecasts a similar level of mandatory investments, driven largely by:

- **Preparing to connect the new Niagara South hospital;**
- **Work to accommodate the 2021 Canada Summer Games in the Niagara Region, and;**
- **Work to accommodate growth and future electricity capacity needs.**

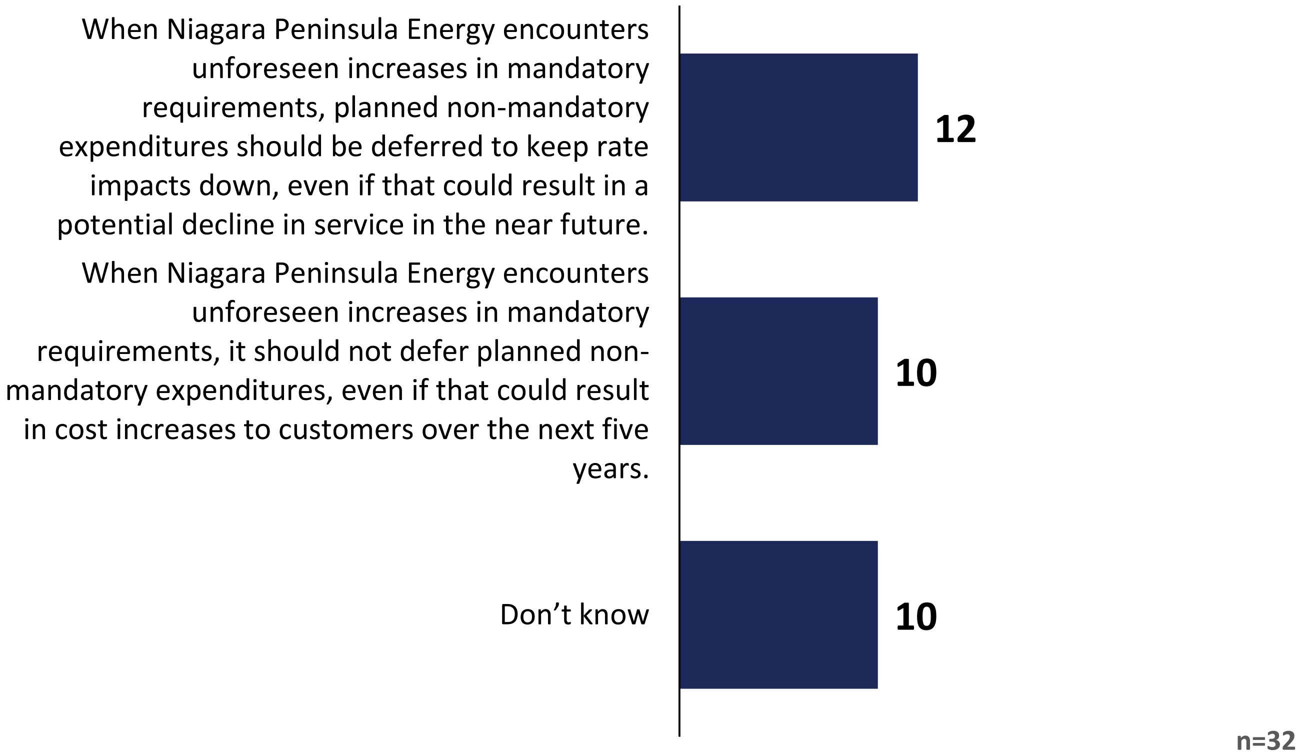
Representative Workbook

Approach to Mandatory Investments

Commercial
GS > 50 kW

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to mandatory and non-mandatory spending?

niagara peninsula energy inc.
Your Local Utility



Additional Feedback (n=6) Verbatim Responses
26/32 of respondents did not provide additional feedback

Again...options provided are too simplistic. Must be decided on a case by case basis.
Case by case basis except for mandatory if I understand the word properly.
Hire smarter people nothing is unforeseen
Service is very important to long-term care. However, we are also very sensitive to large price fluctuations as we are non-profit, charitable, and dependent on the Ontario government for much of our funding.
We need the service, what are we talking a $2 coffee increase year to year instead of 5 years to wait, need to modernize this cost of service procedure, not even our business plans are 5 years anymore- 2 years, keep it to inflation year over year instead of big jump in 5 years and if these non-mandatory spending occurs the adjustments are easier to do for both NPEI and probably the regulator.
Your question does not make sense.

Making Choices (1 of 7)

Overhead Pole Replacement

A recent asset health condition assessment shows that **575 or approximately 3%** of the poles in NPEI's distribution system are in *poor* or *very poor* condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a car accident.

On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period.

NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

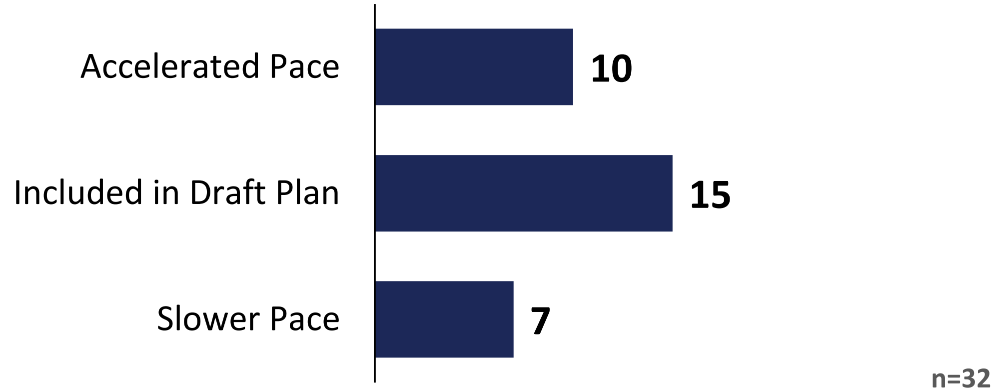
Option	Poles Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.52 per month annually ($6.24 more per year)*	1,000 by 2025 (200 per year)	Address the very poor and some of the poor condition poles identified in the Asset Condition Assessment.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	500 by 2025 (100 per year)	Address most of the very poor condition poles identified in the Asset Condition Assessment and annual pole inspections by 2025.
Slower Pace ***Decrease*** *of $0.25 per month annually ($3.00 less per year)*	250 by 2025 (50 per year)	Address only the poles in need of immediate replacement, as identified in the annual pole inspection report.

Representative Workbook

Overhead Pole Replacement

Q Which of the following options do you prefer?

niagara peninsula energy inc. Your Local Utility



Additional Feedback (n=3) Verbatim Responses 29/32 of respondents did not provide additional feedback
Invest in underground moving forward instead of replacing pole to pole. In the long run it costs more if we don't invest up front.
Is your cost including the cost of money whether borrowing or not earning interest? I would take the slowest pace if it does not impact service but I'm not sure that's true.
Why are you replacing poles, put this infrastructure under ground. Also why would you leave very poor poles up?

Making Choices (2 of 7)

Overhead transformer replacement

Transformers are a critical piece of distribution equipment that reduce voltage from the higher levels that are more efficient to move electricity long distances to lower levels that are safer to connect to homes and businesses. They are typically either located on the ground, in underground vaults, or attached to distribution poles

A recent asset health condition assessment shows that **1,251 or approximately 21%** of the overhead transformers in NPEI's distribution system are in poor or very poor condition.

Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances.

However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses.

NPEI is proposing a new program to proactively replace **250 of the 677 or 37%** of the overhead transformers identified as very poor condition before they fail over the course of the next five years.

As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

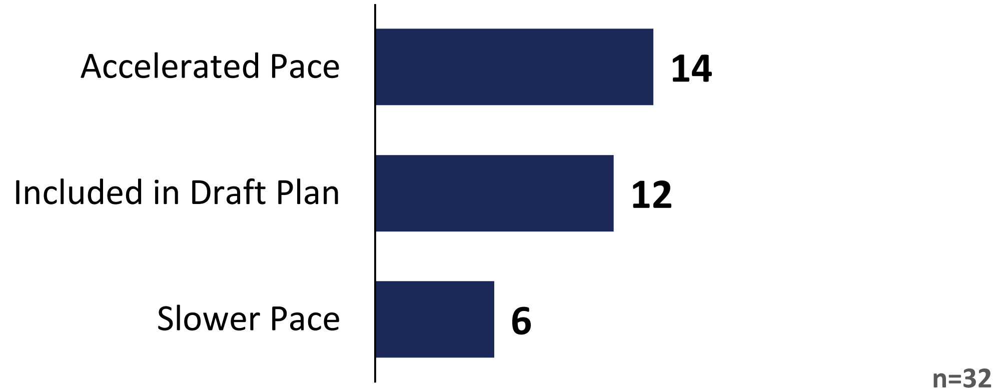
Option	Transformers Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.18 per month annually ($2.16 more per year)*	375 by 2025 (75 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	250 by 2025 (50 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Slower Pace ***Decrease*** *of $0.16 per month annually ($1.92 less per year)*	125 by 2025 (25 per year)	Address only the worst of the polemount transformers identified as very poor in the Asset Condition Assessment report.

Representative Workbook

Overhead transformer replacement

Q Which of the following options do you prefer?

niagara peninsula energy inc.
Your Local Utility



Additional Feedback (n=3) Verbatim Responses 29/32 of respondents did not provide additional feedback
Why overhead to overhead, not effective anymore with all these wind and weather related incidents.
Same as pervious answer.
Again, why are poor transformers still there.... this infrastructure needs to be moved underground.

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Making Choices (3 of 7)

Converting Outdated Underground Kiosk Transformers

NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program has been pushed off, and today, there remains 75 transformers in need of replacement.

NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.

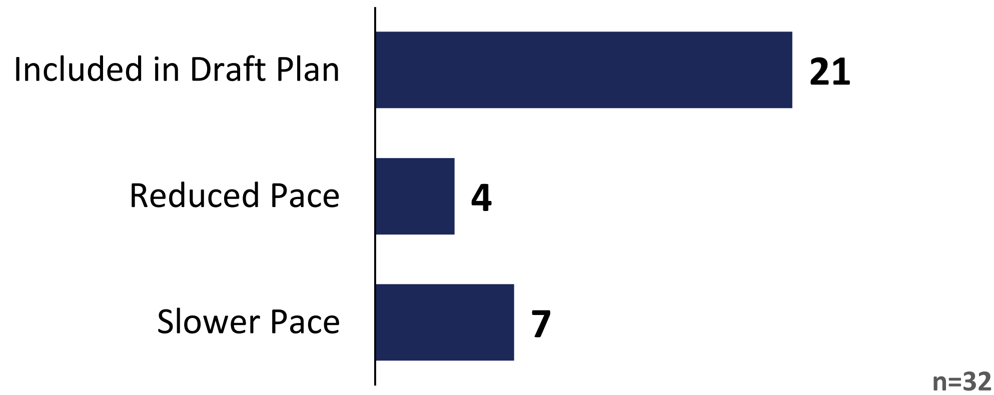
Option	Transformers Installed	Expected Outcome
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	55 by 2025 (11 per year)	Work towards eliminating all old installations over the next 7 years.
Reduced Pace ***Decrease*** *of $0.40 per month annually ($4.80 less per year)*	25 by 2025 (5 per year)	Work towards eliminating all old installations over the next 15 years.
Slower Pace ***Decrease*** *of $0.61 per month annually ($7.32 less per year)*	10 by 2025 (2 per year)	Work towards eliminating all old installations over the next 35 years.

Representative Workbook

Converting Outdated Underground Kiosk Transformers

Commercial
GS > 50 kW

Q Which of the following options do you prefer?



Additional Feedback (n=2) Verbatim Responses 30/32 of respondents did not provide additional feedback
UNDERGROUND!
Same as pervious answer.

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Making Choices (4 of 7)

Underground cable replacement

Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years.

Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses.

Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.

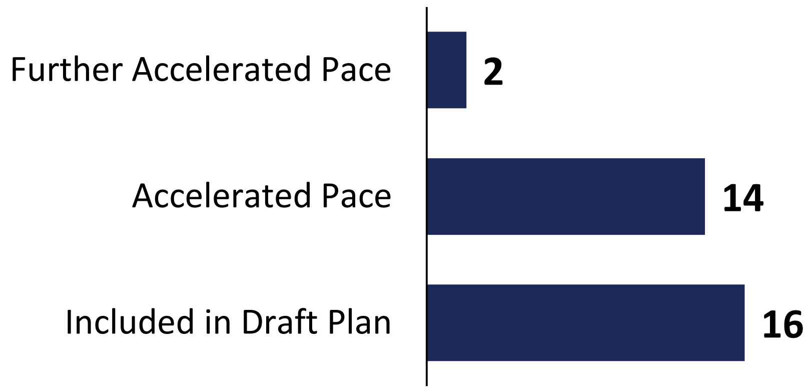
Option	Km of cable installed	Expected Outcome
Further Accelerated Pace ***Additional*** *$2.64 per month annually ($31.68 more per year)*	24 km by 2025 (4.8 km per year)	Proactively replace more of the cables identified as past end of life in the Asset Condition Assessment Report.
Accelerated Pace ***Additional*** *$1.21 per month annually ($14.52 more per year)*	12 km by 2025 (2.4 km per year)	Proactively replace some of the cables identified as past end of life in the Asset Condition Assessment Report.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	2 km by 2025 (0.4 km per year)	Replace cables past end of life as other work is being completed on associated switchgear or riser poles.

Representative Workbook

Underground cable replacement

Commercial
GS > 50 kW

Q Which of the following options do you prefer?



n=32

Additional Feedback (n=2) Verbatim Responses 30/32 of respondents did not provide additional feedback
So you talking a 1 per month.
Same as pervious answer.

Making Choices (5 of 7)

Subdivision underground rehabilitation

71 of the subdivisions in NPEI's service territory were constructed with **direct buried cable** which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier.

While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life.

In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs.

In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed.

Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time.

Between 2021 and 2025, NPEI is proposing a new program that will proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.

Option	Km of vault installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.48 per month annually ($5.76 more per year)*	30 km by 2025 (6 km per year)	Install 6 km of ducts or approximately four subdivisions per year.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	15 km by 2025 (3 km per year)	Install 3 km of ducts or approximately two subdivisions per year.
Slower Pace ***Decrease*** *of $0.23 per month annually ($2.76 less per year)*	7.5 km by 2025 (1.5 km per year)	Install 1.5 km of ducts or approximately one subdivision per year.

Representative Workbook

Subdivision underground rehabilitation

Commercial
GS > 50 kW

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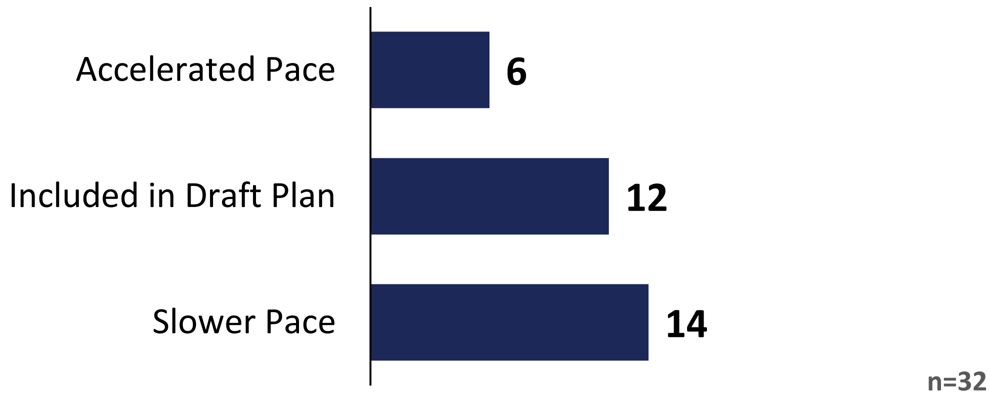
Q Which of the following options do you prefer?



Additional Feedback (n=2) Verbatim Responses 30/32 of respondents did not provide additional feedback
This should be costed out at beginning with the developer costs. They should bear the costs. Not charge enough upfront but should consider maintenance costs to sustain this service up to lifespan of the underground wiring. Why is NPEI barring these costs, factor this in the beginning of the costs to the developers as they make the money on the lots/houses sold.
Same as pervious answer.

Making Choices (6 of 7)

Overhead rebuilds

Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system.

A recent asset health condition assessment identified a total of **60 areas** within NPEI's service territory that require complete overhead rebuilds**.** Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section.

This program is intended to contribute to the "betterment" of the overhead system by;

- Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and;
- Improving system aesthetics with new and taller poles.

On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's current approach would rebuild **40 out of 60 areas** in the 2021 to 2025 period.

NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.

Option	Overhead rebuilds	Expected Outcome
Accelerated Pace ***Additional*** *$0.71 per month annually ($8.52 more per year)*	61 km by 2025 (12.2 km per year)	Rebuild 12.2 km per year or approximately 10 projects per year
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	48.5 km by 2025 (9.7 km per year)	Rebuild areas with assets that have been identified as very poor in Asset Condition Assessment. Rebuild 9.7 km per year or approximately 8 projects per year
Slower Pace ***Decrease*** *of $0.70 per month annually ($8.40 less per year)*	36 km by 2025 (7.2 km per year)	Rebuild 7.2 km per year or approximately 6 projects per year

Representative Workbook

Overhead rebuilds

Commercial
GS > 50 kW

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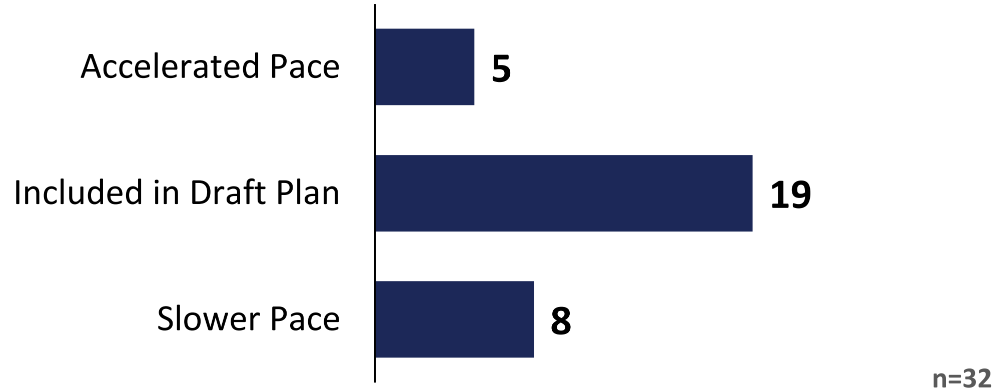
Q Which of the following options do you prefer?



Additional Feedback (n=2) Verbatim Responses 30/32 of respondents did not provide additional feedback
Need to invest in underground instead -yes poles cheaper but costs the customers more in the long run.
Same as pervious answer.
Underground?

Making Choices (7 of 7)

Grid modernization

New technology has changed the way that NPEI can manage and monitor the distribution system.

Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory.

This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event.

On average, since 2014, NPEI has installing approximately two remote devices per year, with focus on more rural, lower density areas. That said, there is an opportunity to install this monitoring and control equipment more quickly or slowly.

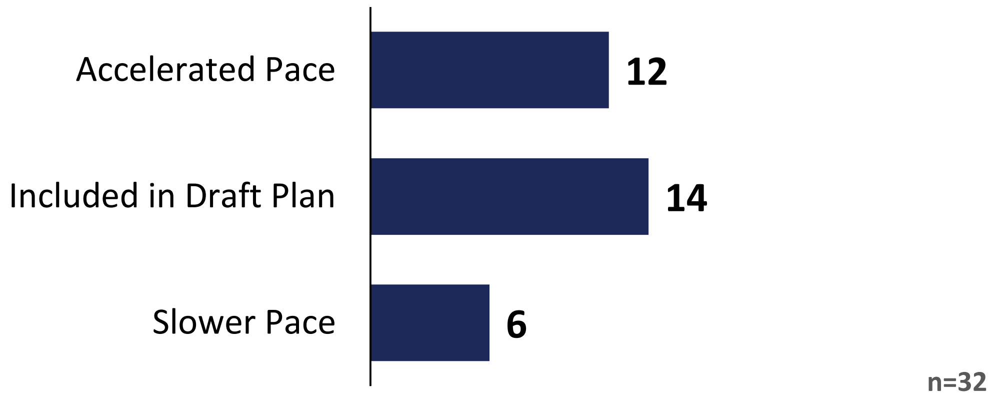
Option	Devices installed	Expected Outcome
Accelerated Pace ***<u>Additional</u>*** *$0.14 per month annually ($1.68 more per year)*	20 devices (4 per year)	NPEI to double installation rate to four devices per year.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	10 Devices (2 per year)	Remain at current installation pace of two devices per year. Install new devices to expand NPEI's Smart Grid network. These devices provide better monitoring capability on the system, which leads to improved restoration times during outages.
Slower Pace ***<u>Decrease</u>*** *of $0.06 per month annually ($0.72 less per year)*	5 Devices (1 per year)	NPEI to cut rate of installation in half to one device per year.

Representative Workbook
Grid modernization

Commercial
GS > 50 kW

Q Which of the following options do you prefer?

niagara peninsula energy inc. Your Local Utility



Additional Feedback (n=1) Verbatim Responses
31/32 of respondents did not provide additional feedback

Need to get with the times, we want our local hydro to be our facilitator for our energy needs now and for the future. Private sector will be too expensive for businesses. OEB as the regulator should realize this as it is key for business to go through their hydro as we know they will not gauge us and know our business and assist us.

Representative Workbook

Change in Initial vs. Final Response by Project

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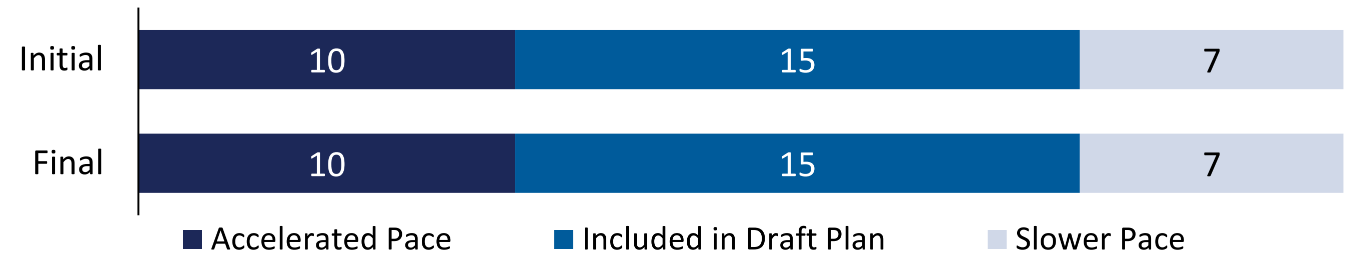
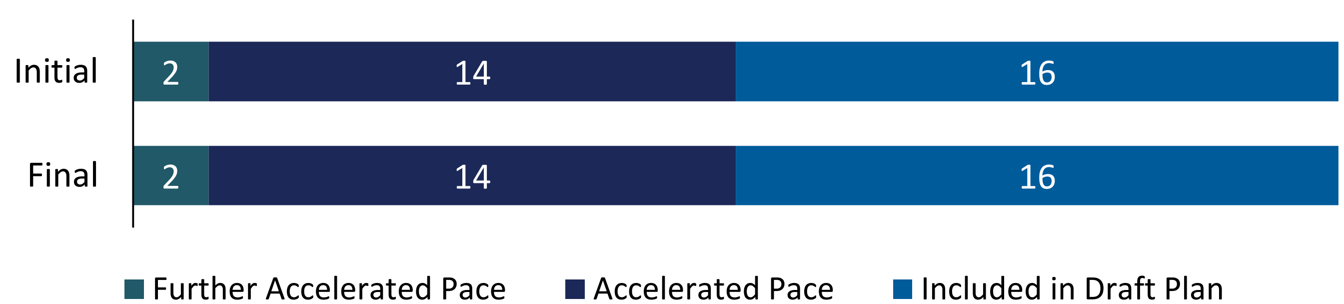
Q Overhead Pole Replacement



Q Overhead Transformer Replacement

Q Converting Outdated Underground Kiosk Transformers

Q Underground Cable Replacement

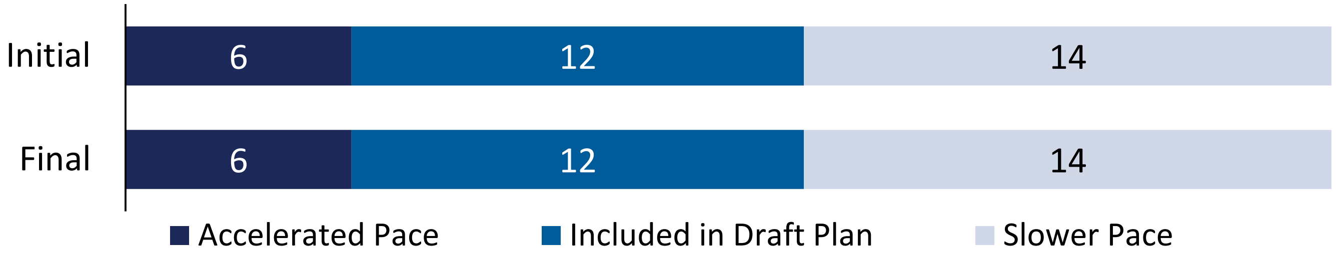


Representative Workbook

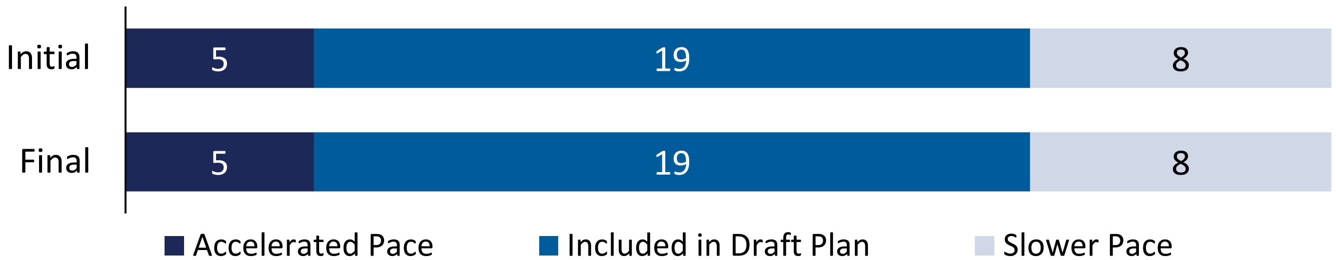
Change in Initial vs. Final Response by Project

Commercial
GS > 50 kW

Q Subdivision Underground Rehabilitation



Q Overhead Rebuilds



Q Grid Modernization

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Impact of Choices

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Again, it is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $65.65 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical mid-sized business customer would see the distribution portion of their electricity bill increase by $105.39.
- As a result, the distribution charges on the typical mid-sized business customer's monthly bill would increase from $747.52 in 2020 to $852.91 by 2025.

Estimated Typical Mid-Sized Business Annual Increase in Monthly Bill (5 year forecast)

	Year	Average Mid-Sized Business Bill	Distribution Portion of Bill	Incremental Rate Change	% Change * (on distribution portion of bill)
Current Rate	2019	$11,661.27	$738.65		
Budgeted Rate	2020	$11,876.06	$747.52	$8.87	1.20%
Forecast for next rate period	2021	$11,948.38	$813.17	$65.65	8.78%
	2022	$12,127.61	$822.92	$9.76	1.20%
	2023	$12,309.52	$832.80	$9.88	1.20%
	2024	$12,494.17	$842.79	$9.99	1.20%
	2025	$12,681.58	$852.91	$10.11	1.20%
				$105.39	

*** These estimates are preliminary, and are subject to your feedback as the business plan is finalized .**

Representative Workbook

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

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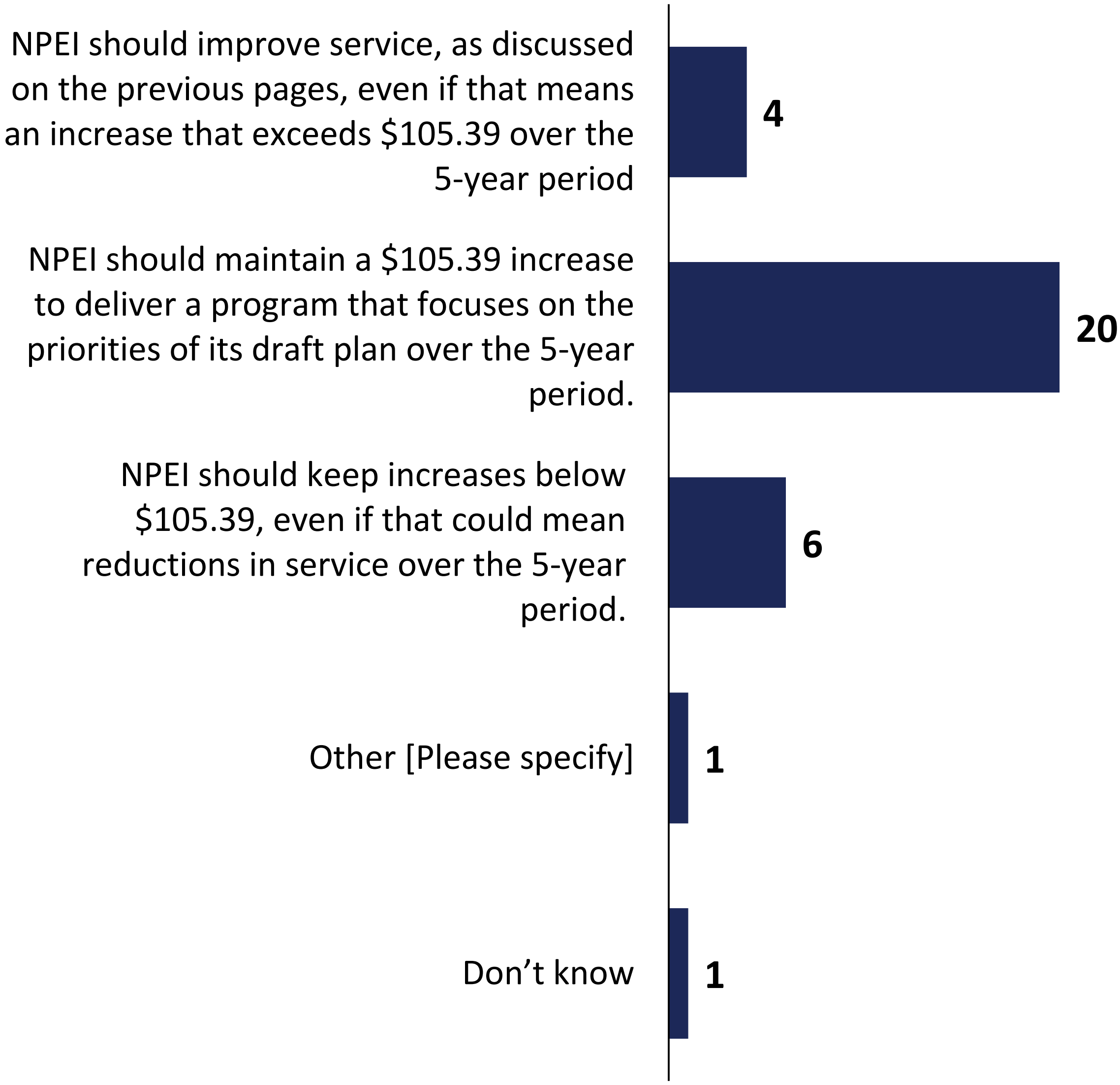
Q

Considering what you know about Niagara Peninsula Energy's draft plan – which would see the typical mid-sized business customer's distribution portion of their bill increase by $105.39 over the 5-year period – which of the following best represents your point of view?



n=32

Representative Workbook

Final Comments

Q Thinking about your answer to the previous question, why do you feel that NPEI should take that approach over the 2021-2025 period?

Final Thoughts (n=8) Verbatim Responses 24/32 of respondents did not provide additional feedback
There is not cap it just says an increase that exceeds, too vague a statement. How much more? A moderate increase would be acceptable.
NPEI should carefully pace increases in rates to avoid excessive cost burden to businesses.
NPE is a business just like my business owning apartment buildings. You spend the money your comfortable with and increase what you need to do such work but keep in mind your business also has to spend money and not just your customers.
Might as well bite the bullet now, it should save us money in the long run. Electricity is part of the lifeline of our local economy and therefore we should keep the grid in good condition. As a business owner I experience from close by what the direct but also the indirect cost to my business when a power outage occurs.
Maximize existing infrastructure to it's fullest potential. If it ain't broke, don't fix it.
Leverage Technology to communicate with customers, customers expectations have change over the years with "SMART" tech, phones, appliances, LED, Battery Storage etc.. But the regulator doesn't provide the hydro to move with the times and facilitate this for us. I trust my local utility over private sector which have NO OVERSIGHT and would gauge the businesses. Offer conservation programs to the businesses and educational opportunities to maintain our electricity costs in order that we can sustain our businesses.
It seems like the best approach with the least negative impact to the customer
Deferring investment is likely more costly in the long-run.

Q Do you have any final comments regarding NPEI or the customer engagement that you just completed?

Final Thoughts (n=3) Verbatim Responses 29/32 of respondents did not provide additional feedback
Dedicated conservation managers who assist businesses with energy savings and incentives (ERIP, EBCx projects, Global Adjustment Class reviews, etc.) are a valuable asset and vital to business goals in managing energy costs.
NPEI is a local utility that gives back to the communities and when I call they answer the questions, when we were involved with the conservation programs, a representative from the Utility came out and assisted us the applications and educated us and so customer engagement should done on an ongoing basis NOT every 5 years when the OEB funds it though this RATE Process you indicated. This is too long of a survey, do it more often.
Very beneficial and upfront.

Representative Workbook

Background Information

Designing Rates

Potential changes to fixed versus variable distribution rates

In recent conversations with mid-sized and large business customers, the topic of cost certainty regarding distribution rates has been raised.

Currently, distribution rates for customers, like yourself, are based on a 15% fixed and 85% variable rate. This means that 85% of your distribution charges are largely based on how much electricity you use.

In order to improve cost certainty, some customers have expressed a desire to move to a more fixed distribution rate. In its current draft plan, NPEI is proposing to increase the fixed portion of the distribution charge to 21%. Not only does this create more cost certainty for customers, but it also provides revenue certainty for NPEI to operate and maintain the distribution system

For customers who have predictable electricity usage habits, this change likely wouldn't have much of an impact, while creating more certainty for those whose electricity usage fluctuates more regularly.

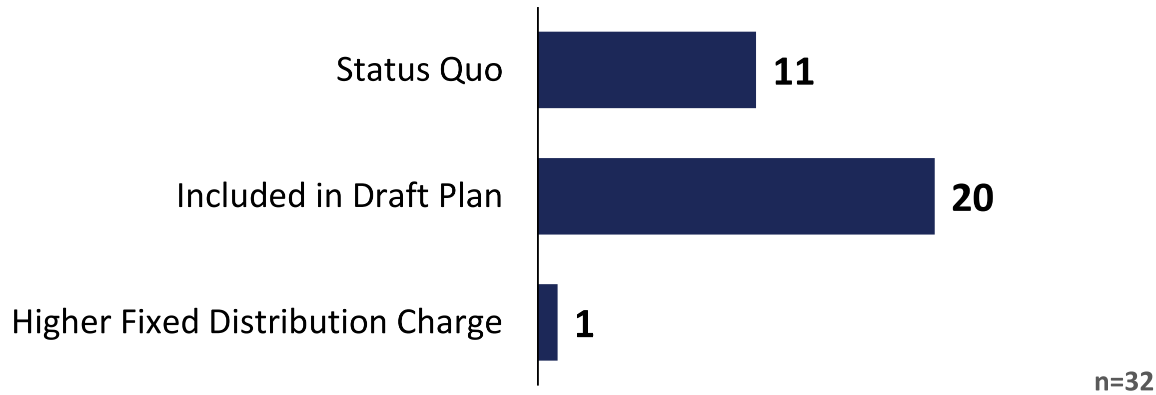
NPEI is looking to understand what fixed-variable split you would like to see the utility use over the next 5-years and beyond.

Option	Fixed-Variable Split	Expected Fixed Versus Variable Charge
Status Quo	15% fixed; 85% variable	Total distribution charge for a typical mid-sized business customer would be $813.37 in 2021 • $118.75 fixed monthly distribution charge • $3.86 per kW variable charge
Included in Draft Plan	21% fixed; 79% variable	Total distribution charge for a typical mid-sized business customer would be $813.17 in 2021 • $161.17 fixed monthly distribution charge • $3.62 per kW variable charge
Higher Fixed Distribution Charge	33% fixed; 66% variable	Total distribution charge for a typical mid-sized business customer would be $813.56 in 2021 • $256.15 fixed monthly distribution charge • $3.10 per kW variable charge

Representative Workbook

Potential changes to fixed versus variable distribution rates

Q Which of the following options do you prefer?



Final Thoughts (n=3) Verbatim Responses 29/32 of respondents did not provide additional feedback
Higher fixed rate would impact the payback as we invest in electricity saving technology and initiatives.
I do not really like any of the options provided and cannot make any recommendations as I believe an audit is required of the NPE bills to see if 6% as estimated in correct.
The higher the fixed rate, the less incentive there is to conserve.

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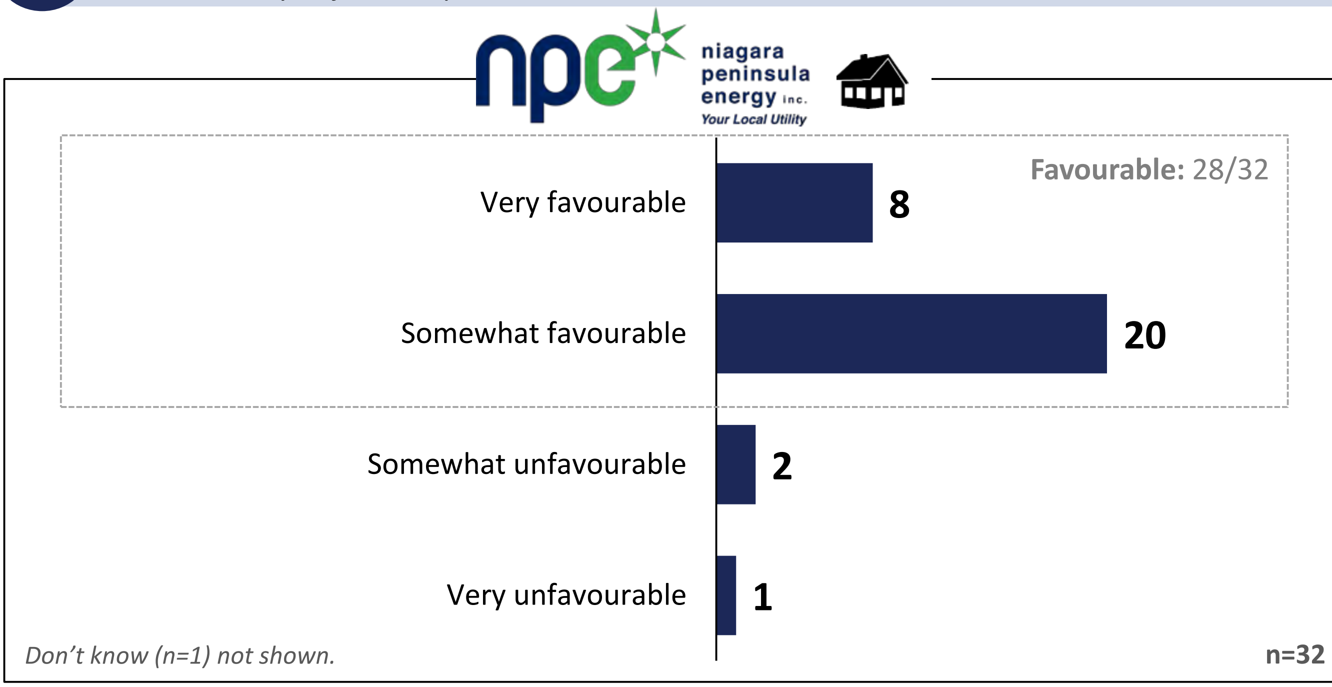
Representative Workbook

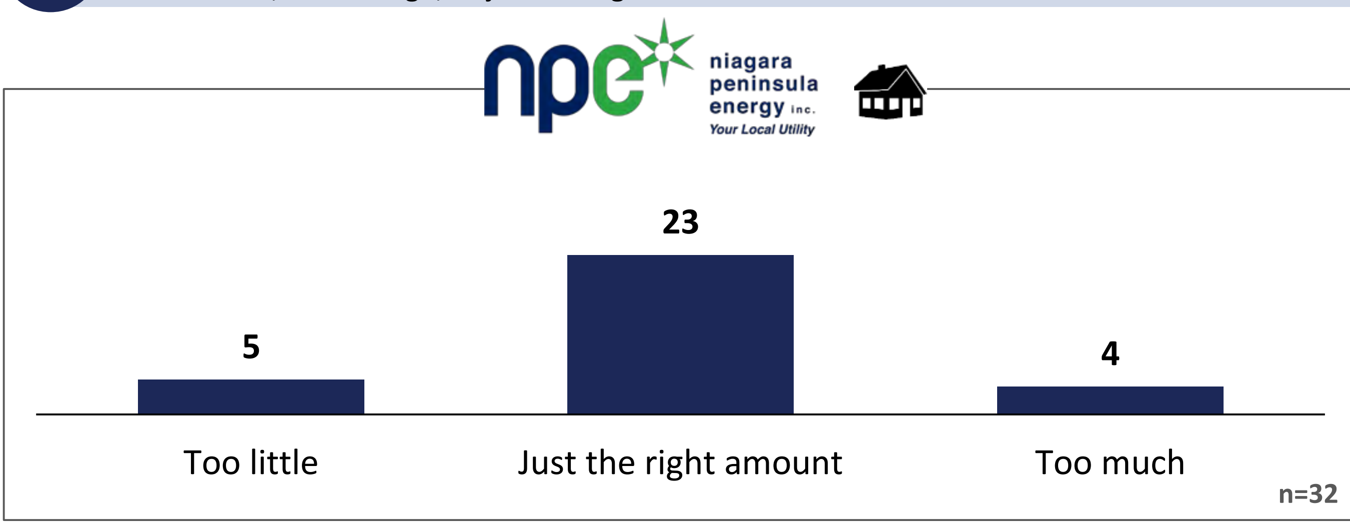
Final Thoughts: Workbook Diagnostics

Commercial
GS > 50 kW

Q **Overall Impression**: Overall, did you have a favourable or unfavourable impression of the consultation you just completed?



Q **Volume of Information:** In this consultation, do you feel that NPEI provided too much information, not enough, or just the right amount?



Representative Workbook

Content Covered

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Q Was there any content missing that you would have liked to have seen included in this consultation?

Final Thoughts (n=4) Verbatim Responses 28/32 of respondents did not provide additional feedback
A number or contact at NPE to discuss the 6% charge which seems quite erroneous
Any incentive program for the customer side to lighten the load on the NPEI side.
Difficult to give an opinion on expenses without the whole picture.
Information on "Save on Energy" Programs

Q Is there anything that you would still like answered?

Final Thoughts (n=3) Verbatim Responses 29/32 of respondents did not provide additional feedback
Please tell me why there are employees and management making over $150000 a year working in public utilities .
How did NPE come up with 6%, what is the highest percentage and the lowest percentage... is 6% an average? our bills in 2018 it was 36% with the global adjustment being around the same %.... your math does not seem right.
As part of above, is it possible that we can get a brake on the monthly load factor or delivery charge if our company invest in technology or equipment to help out NPEI by partially going off the grid as needed.

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Building Understanding.

Personalized research to connect you and your audiences.

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INNOVATIVE RESEARCH GROUP

2021-2025 Rate Application

Voluntary Report

niagara peninsula energy inc.
Your Local Utility

This report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Niagara Peninsula Energy Inc.

January 2020

STRICTLY PRIVILEGED AND CONFIDENTIAL

Voluntary Workbook
Survey Design & Methodology

INNOVATIVE was engaged by NPEI to gather input on preferences on program timing and balancing outcomes. **Pages 3 to 44** show the actual pages of the workbook completed by customers (for illustration, the residential version has been used. Refer to the Representative Report for the small business version). The only additions are the actual results.

Field Dates & Workbook Delivery

The **Voluntary Online Workbook** was accessible to all Niagara Peninsula Energy residential and small business customers between **December 2nd and December 17th, 2019**.

INNOVATIVE hosted the online portal at *NPEICustomerEngagement.ca*.

NPEI promoted the voluntary workbook via their website and social media.

The website saved their progress as they answered each question, thus preventing customers from completing questions repeatedly. Upon completion, the site was no longer accessible at the web address given. Each customer was able to select their rate class, ultimately providing them with a workbook customised for whether they were a residential or small business customer.

Voluntary Online Workbook Completes

A total of **133** (unweighted) NPEI residential and small business customers completed the voluntary online workbook via the generic website link. Due to the small number of NPEI small business customers who completed the voluntary workbook, results from both rate classes have been combined for analysis purposes.

The voluntary online workbook sample has not been weighted, therefore, is not representative of the broader NPEI customer base.

Unweighted Sample	Completes	Workbook Distribution
Residential	224	**96%**
Small Business	9	**4%**
Total	**233**	**100%**

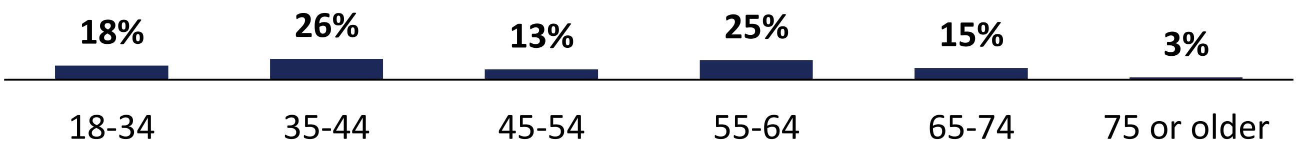
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Voluntary Workbook

Demographic Breakdown

Residential & Small Business

Q Age (Residential Only)



“Prefer not to say” (1%)

n=224

Q Gender (Residential Only)

“Prefer not to say” (2%)

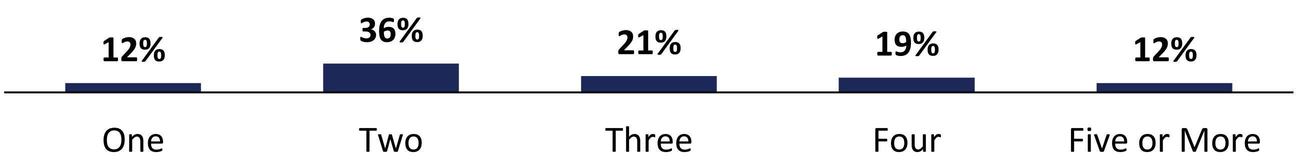
n=224

Voluntary Workbook

Demographic Breakdown

Residential &
Small Business

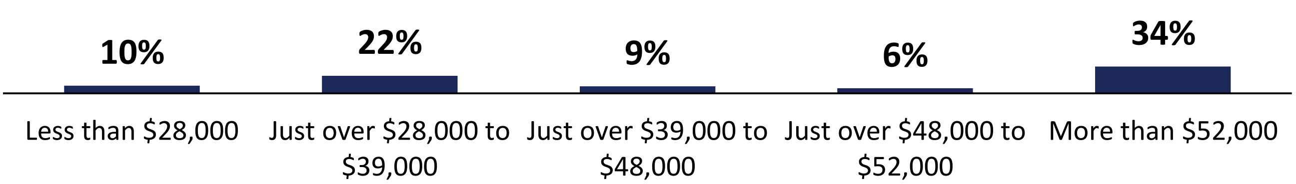
Q Household Size (Residential Only)



"Prefer not to say" (1%)

n=224

Q After Tax Household Income (Residential Only)



"Prefer not to say" (19%)

n=224

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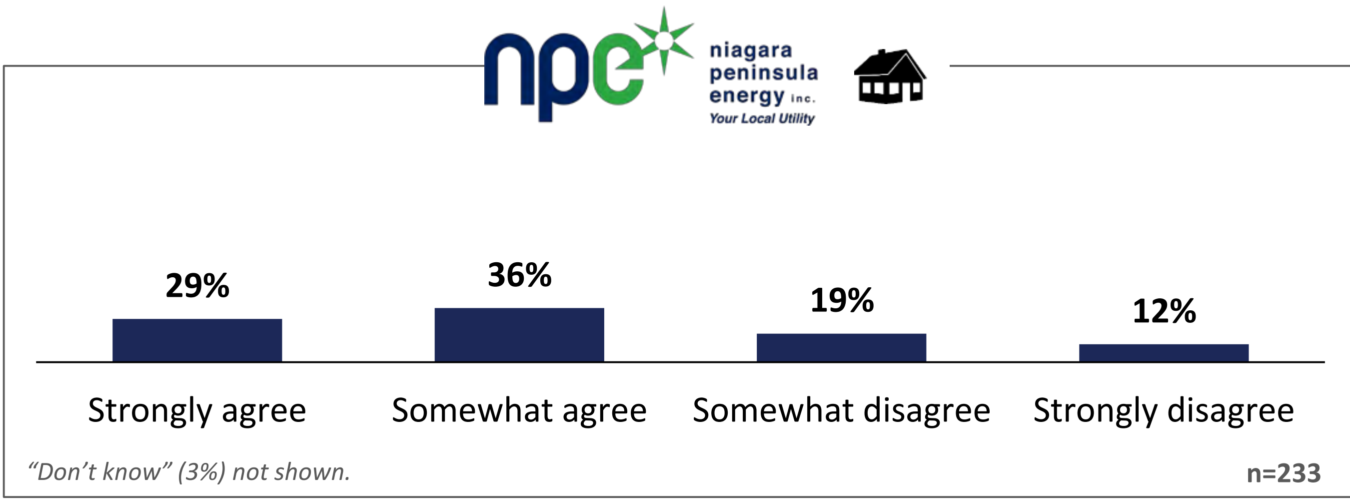
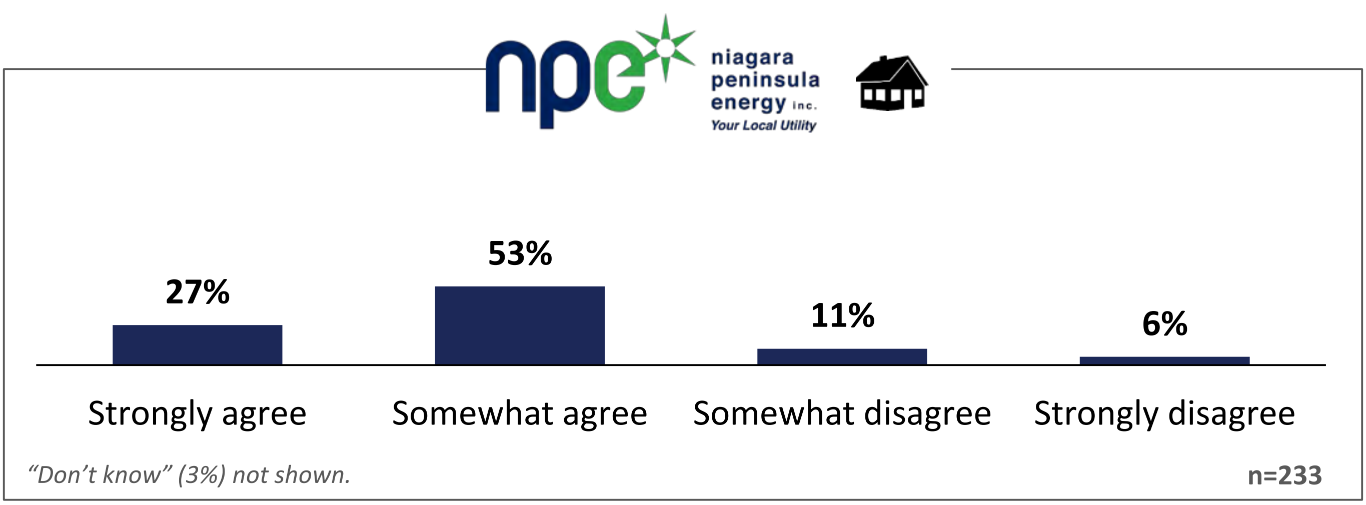
Voluntary Workbook
Environmental Controls

Thinking generally about the electricity system in Ontario, including generation, transmission and local distribution, do you agree or disagree with the following statements?

Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



Q Customers are well served by the electricity system in Ontario.



Voluntary Workbook
Background Information

Niagara Peninsula Energy Inc.
EB-2020-0040
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About this Consultation

Welcome to Niagara Peninsula Energy's Customer Engagement!

Niagara Peninsula Energy (NPEI) needs your input on choices that will impact the services you receive and the rates that you pay.

- **NPEI** is developing its investment plan for 2021 to 2025. This plan will determine the investments NPEI will make in equipment and infrastructure; the services it provides; and the rates you pay.
- As **NPEI** plans for the future, they want to ensure their business decisions are aligned with customers priorities, preferences, and needs.
- Throughout this survey, information will be provided in an effort to give you more background on which to base your responses.
- While responding to the following questions, remember that there are no wrong answers, and that your individual responses will remain anonymous.
- This customer engagement will take approximately 25-35 minutes to complete, depending on the level of feedback you wish to provide. Your progress will be saved as you move through the workbook, meaning you can leave and return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired NPEI to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one (1) $500 cash prize.

Voluntary Workbook

Background Information

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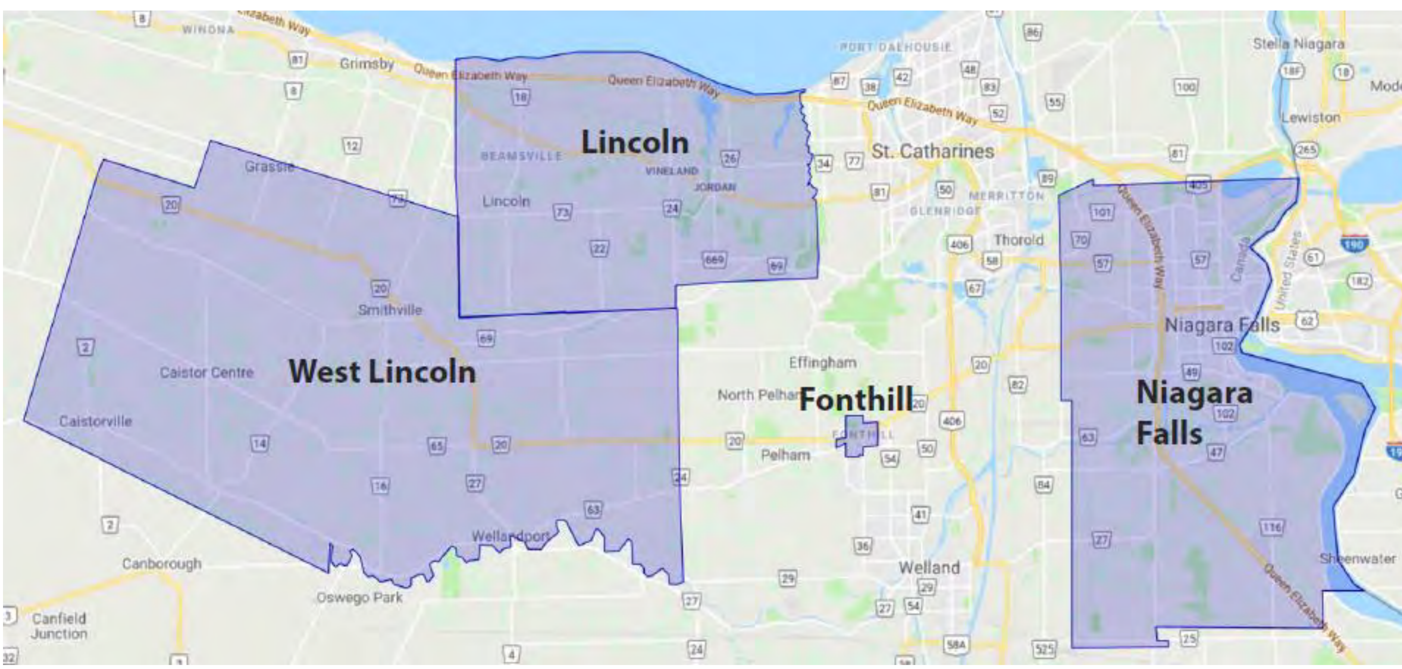
Electricity 101

Who is Niagara Peninsula Energy?

NPEI provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham, and Township of West Lincoln.

- NPEI serves an area of approximately 827 square kilometers and a customer base of approximately 55,600 residential and business customers, containing a mix of urban and rural electrical distribution.
- NPEI is jointly owned by the municipalities it services.
- NPEI manages all aspects of the electricity distribution business and is regulated by the Ontario Energy Board (OEB).
- As a local distribution company (LDC) and regulated entity, NPEI applies for, and receives approval from the regulator to charge for its services.



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Electricity 101

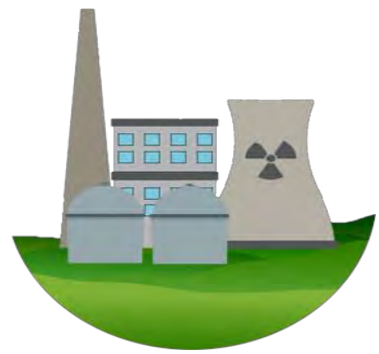
Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

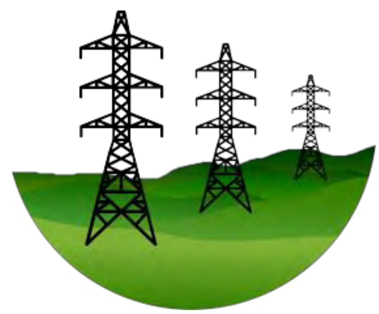
Ontario's electricity is generated using a mix of nuclear, gas-fired, and water power (hydro), as well as biomass and renewable sources such as wind and solar technology. In Ontario, a number of companies own these generating stations but approximately half of the electricity is generated by Ontario Power Generation. The Independent Electricity System Operator (IESO) balances the supply of, and demand for, electricity on a second-by-second basis and directs its flow across the high-voltage transmission lines.



Transmission

How electricity travels across Ontario

Once generated, electricity must be transported to electrical substations across the province. Due to the large amount of power and long distances, transmission normally takes place at high voltages with the lines suspended on large, steel towers. The province has more than 30,000 kilometres of 'electricity highway', most of which is owned and operated by Hydro One.



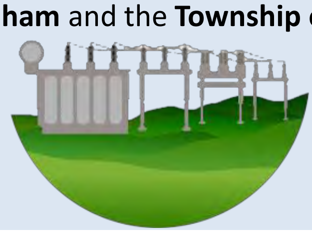
Local Distribution

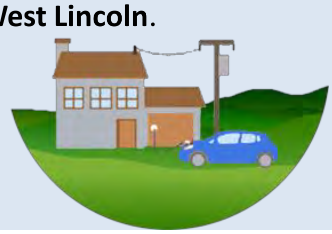
How electricity is delivered to the end-consumer

NPEI is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, NPEI delivers electricity to approximately 55,600 residential and business customers.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.

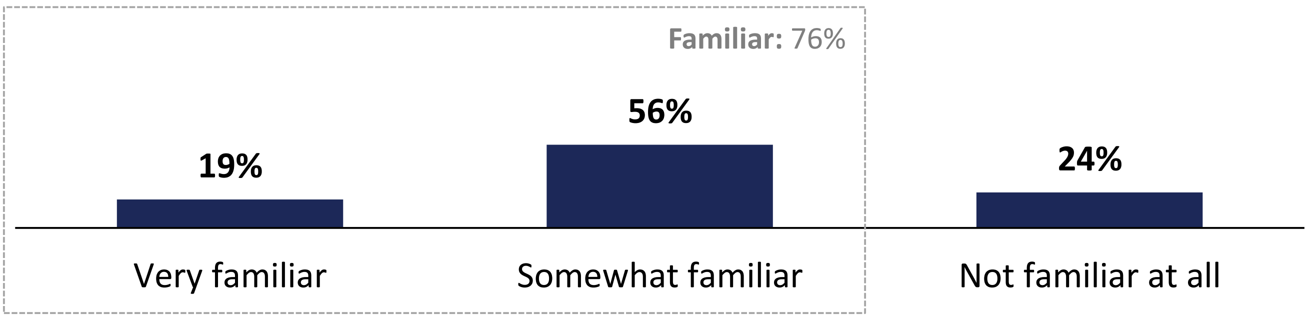




Voluntary Workbook

Familiarity with Ontario's electricity system

Q Before this survey, how familiar were you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?



n=233

Voluntary Workbook
Background Information

Residential & Small Business

Electricity 101

How much of my electricity bill goes to Niagara Peninsula Energy?

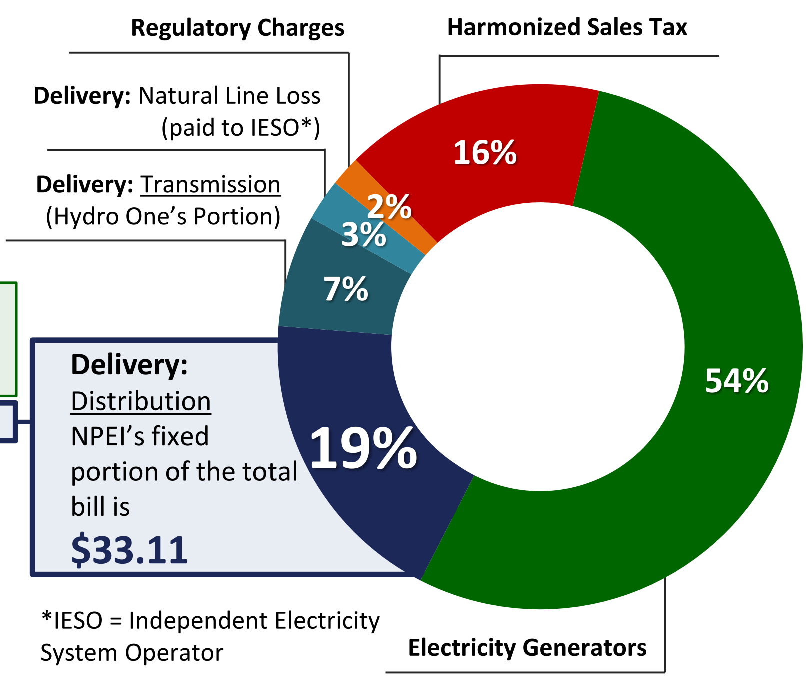
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge.
- Distribution makes up about **19%** of the typical residential customer's bill.
- For residential customers, NPEI's portion of the delivery line on the bill is fixed and does not change based on the amount of electricity you use.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

NPEI Sample Monthly Bill*
(Based on monthly usage of 700 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Off-Peak @ 10.1 ¢/kWh	**45.25**
Mid-Peak @ 14.4 ¢/kWh	**18.14**
On-Peak @ 20.8 ¢/kWh	**26.21**
Delivery	**46.85**
Regulatory Charges	**3.11**
Total Electricity Charges	**$139.56**
HST	**18.14**
Ontario Electricity Rebate*	(-**$44.38)**
Total Amount	**$113.32**



*IESO = Independent Electricity System Operator

* As of November 1, 2019. Chart is based on total bill amount after applying the Ontario Electricity Rebate.

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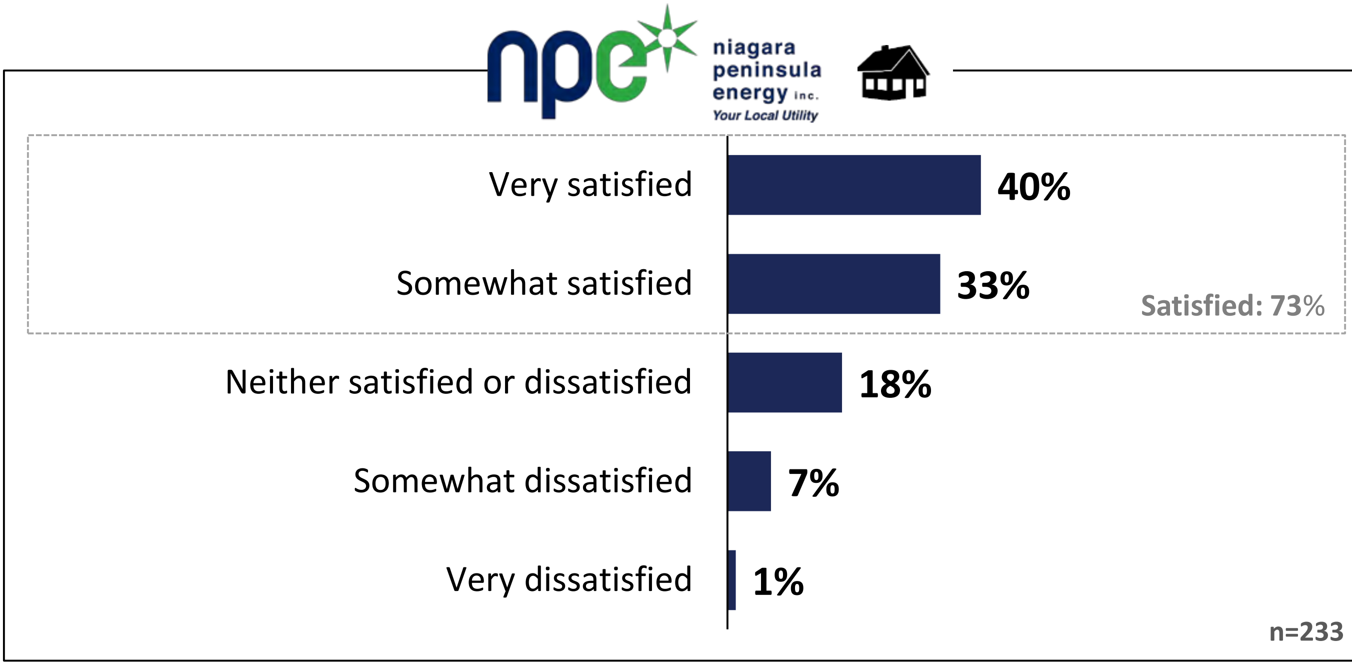
Overall Satisfaction with Niagara Peninsula Energy

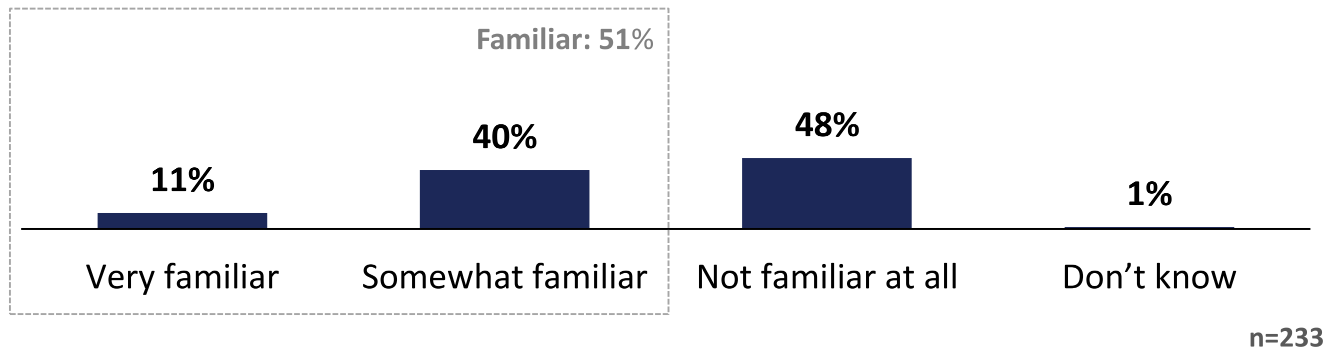
Q Thinking specifically about the services provided to you and your community by Niagara Peninsula Energy, overall, how satisfied or dissatisfied are you with the services that you receive?



Voluntary Workbook

Familiarity with Percentage if Bill Remitted to NPEI

Q Before this survey, how familiar were you with the amount of your electricity bill that went to Niagara Peninsula Energy?



Q Is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to you?

Improving Services (n=84) 64% of respondents did not provide additional feedback	**%**
Lower rates/Charge less	21%
No issues/satisfied with service/keep up the good work	13%
Offer rebates/assistance for low income/seniors	6%
Improve outage communication	5%
Improve customer service/meter reading	5%
Do not increase rates/keep rates affordable	4%
Find internal efficiencies/provide info on cost cutting	4%
Improve reliability/less outages	2%
Decrease/eliminate delivery charges	2%
Improve billing - clarity/payment terms/methods/website	2%
Maintain lines/improve tree clearing	2%
Modify time of use/peak rates	2%
Provide more info on energy consumption/conservation/renewables	2%
None	26%
Don't Know	2%

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Niagara Peninsula Energy Background

Building Niagara Peninsula Energy's draft plan

NPEI has put together its draft business plan based on the information and input from various sources, such as:

- **Legal and regulatory** requirements by continuing to meet its obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected through both ongoing dialogues and specific engagements, such as this.

There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their businesses and serve their customers.

- **Policy**: The Ontario Ministry of Energy, Northern Development and Mines (MNDM) creates energy policy for the province.
- **Regulation**: The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.
- **Operations and Planning**: The Independent Electricity System Operator (IESO) manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

Ontario ENERGY /ÉNERGIE

ONTARIO ENERGY BOARD

ieso Connecting Today. Powering Tomorrow.

Niagara Peninsula Energy Background

How did customer feedback shape Niagara Peninsula Energy's draft plan?

NPEI is placing more emphasis on incorporating customer feedback into the planning process than ever before.

NPEI engages with its customers both in day-to-day interactions and in a variety of customer engagement activities. These interactions help identify customer needs and preferences, and inform how the utility plans for the future.

This past summer, NPEI engaged with **thousands of residential and business customers** from across its service territory – both in person and through telephone and online surveys.

What did NPEI hear from customers like yourself?

1. The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates".

2. Among competing outcomes, **price**, **reliability**, and **finding internal cost efficiencies** are the top three priorities for both residential and small business customers.

3. While keeping price at a reasonable and affordable level is an important priority, many customers feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Considering this feedback, as well as the information and inputs discussed on the previous page, NPEI has developed a draft plan that is responsive to:

1. Legal requirements by continuing to meet its obligations, including safety and reliability;

2. A transformer station upgrade to accommodate the new Niagara South Hospital and future surrounding growth.

3. Mandatory service connections to accommodate new customers and customer-required upgrades, of which NPEI does not have control over how and when these costs are incurred.

4. Customer feedback by:

   a) Keeping distribution price increases as low as possible;

   b) Maintaining long-term performance for customers experiencing average or better service;

   c) Improving service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,

   d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

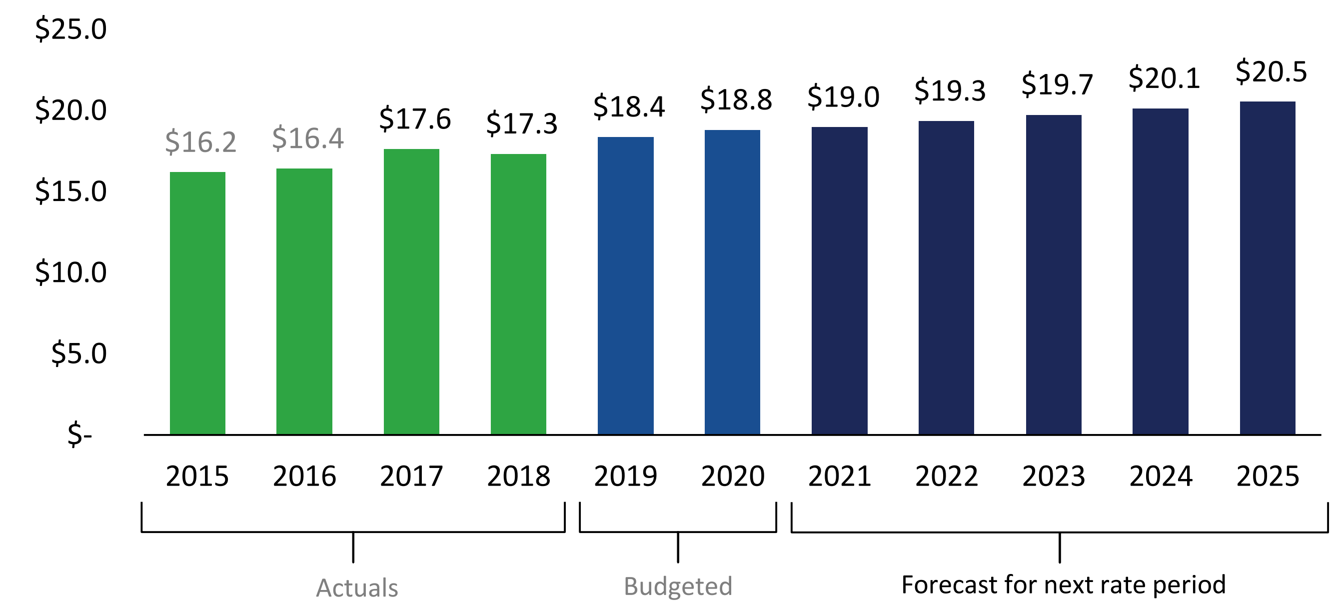
Niagara Peninsula Energy Background

Operating Expenses

In this section, we want to focus on operating expenses and how NPEI compares to its peers.

NPEI's operating budget covers recurring expenses, such as the maintenance of poles, wires, transformers, fleet and buildings as well as proactive maintenance programs such as tree trimming, and payroll for employees. Meter reading, postage, cyber security and hardware/software maintenance expenses are billing and customer service-related expenses. The proposed 5-year plan, between 2021 and 2025, would see NPEI spend an estimated total of $98.7 million on operations.

NPEI's Current and Forecasted Operating Expenses, per Year (Millions)*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI's **operating costs** are benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, NPEI's operating costs per customer was **$311.67**, which is slightly more than some, while less than both Hydro One and Canadian Niagara Power.

2018 Operating & Maintenance and Administration (OM&A) Per Customer ($)

The diverse geographical nature of NPEI's service territory, which is a mix of urban and rural communities is a large consideration/driver of these OM&A costs. In some parts of the service territory, there may be less than 30 customers per kilometer of line. Despite low density, these lines still require the same level of ongoing maintenance, including tree trimming and other expenses that contribute to operating the system; thereby resulting in a higher cost per customer.

Niagara Peninsula Energy Background

Operating Expenses

Recall, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge NPEI's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found at oeb.ca/participate.

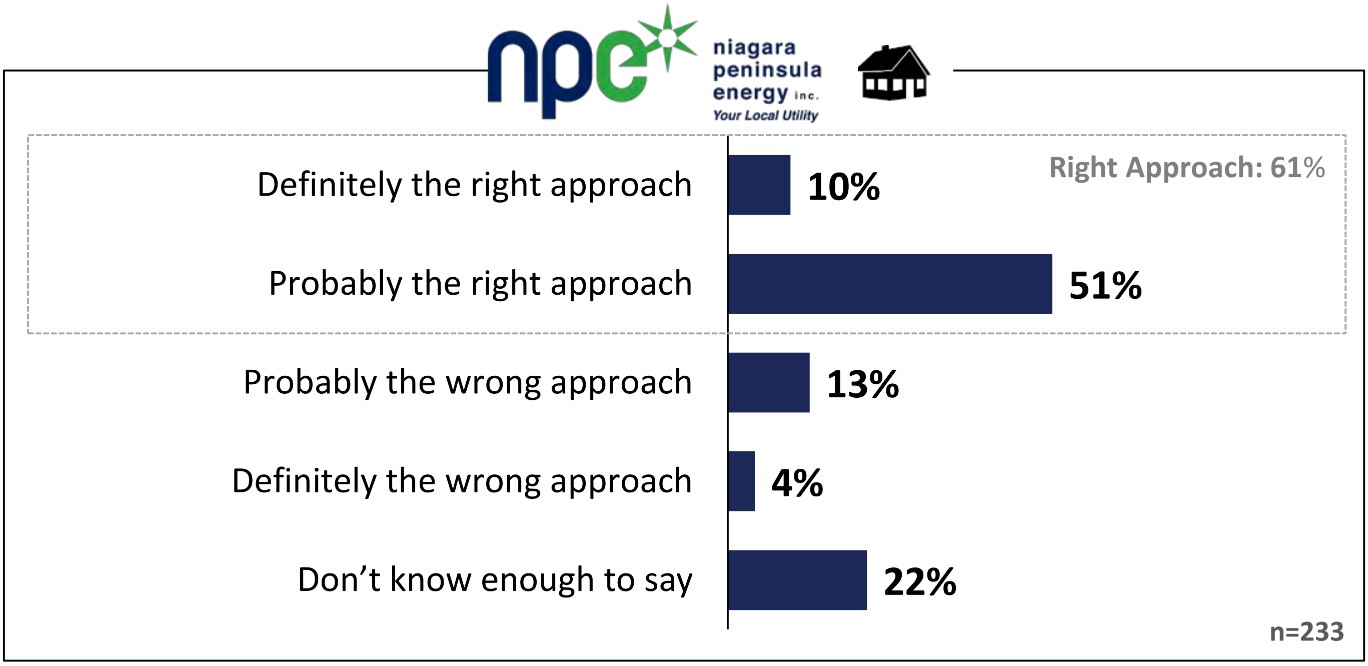
This customer engagement however, is focused on capital investments.

Detailed discussion of NPEI's operating budget is left to experts from the OEB and intervenors in the formal rate application review; this workbook focuses on collecting your view on competing trade-offs in capital investments.

Voluntary Workbook

Approach to Operating Expenses

Q Does leaving the detailed discussion about Niagara Peninsula Energy's operating budget to experts from the OEB and intervenors seem like the right approach or wrong approach to you?



Voluntary Workbook
Background Information

Niagara Peninsula Energy Background

Capital Investments

NPEI's **capital budget** covers items that, once purchased, have lasting benefits over many years. Year-over-year, regardless of external drivers, NPEI will need to make investments in the core distribution system, including poles, wires, cables and transformers.

Based on initial customer input and the approach outlined previously, NPEI believes the capital expenditure required to address system renewal, maintain system reliability and safety, and invest in other infrastructure priorities between 2021 and 2025 is estimated to be **$70.3 million**.

NPEI classifies the costs of four types of capital investment between 2021 and 2025. Each of these four investment categories helps NPEI pace and prioritize projects.

2021-2025 Forecasted Capital Investments

System Renewal ($38.2 million)

These projects are a mix of planned end-of-life replacements and emergency replacements.

Projects Include: Replacement of existing overhead wires, poles, and pole mounted transformers, underground cables and transformers and transformer station upgrades.

System Access ($17.1 million)

"Must do" investments that respond to customer requests for new connections or new infrastructure development.

Projects Include: NPEI's share of new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs.

General Plant ($8.4 million)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

Projects Include: Financial and customer IT systems, enhanced cyber security investments, facility renovations, backup generation, and vehicle replacements.

System Service ($6.6 million)

These investments consist of projects that address capacity constraints, improve system reliability and customer service.

Projects Include: Installation of automated switches and system expansion to supply new development.

Niagara Peninsula Energy Background

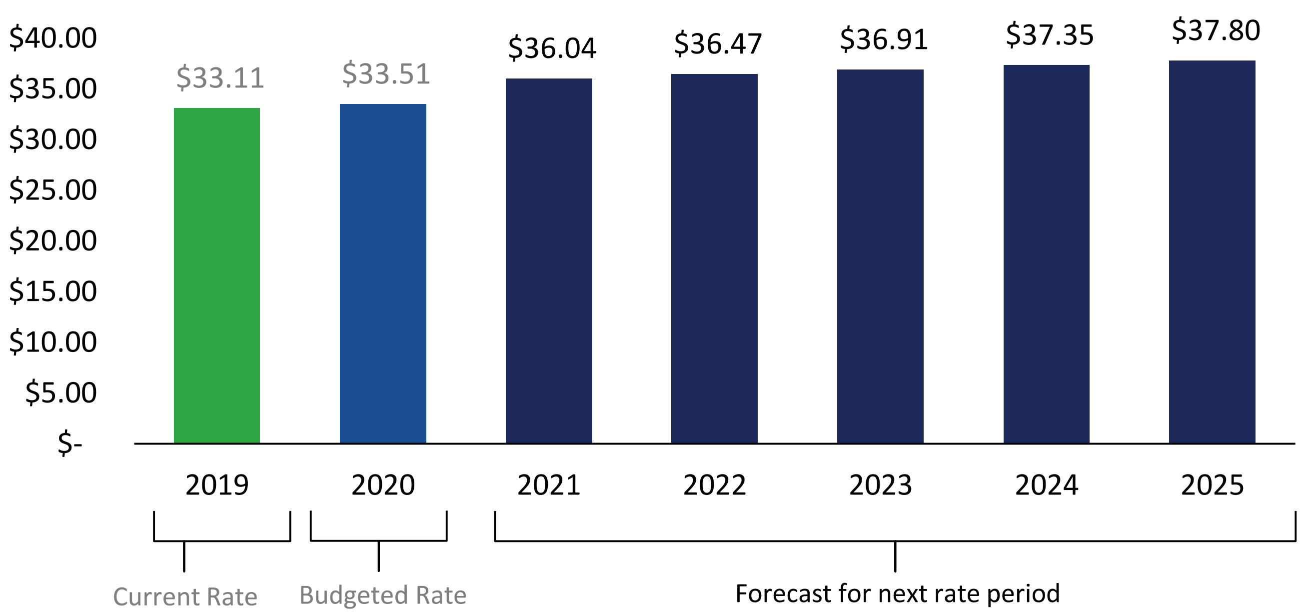
How much will this draft plan cost me?

Remember, the current typical NPEI residential customer's electricity bill is about $113 per month, of which $33.11 goes to NPEI.

It is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $2.53 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by $4.29.
- As a result, the distribution charges on the typical residential customer's monthly bill would increase from $33.51 in 2020 to $37.80 by 2025.

Estimated Residential Monthly Distribution Charge, per Year*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI is looking for your input on its preliminary plan to ensure it is making the spending decisions that matter to you, the customer.

The following sections of this workbook will explore some of the choices Niagara Peninsula Energy needs to make to help finalize its preliminary plan.

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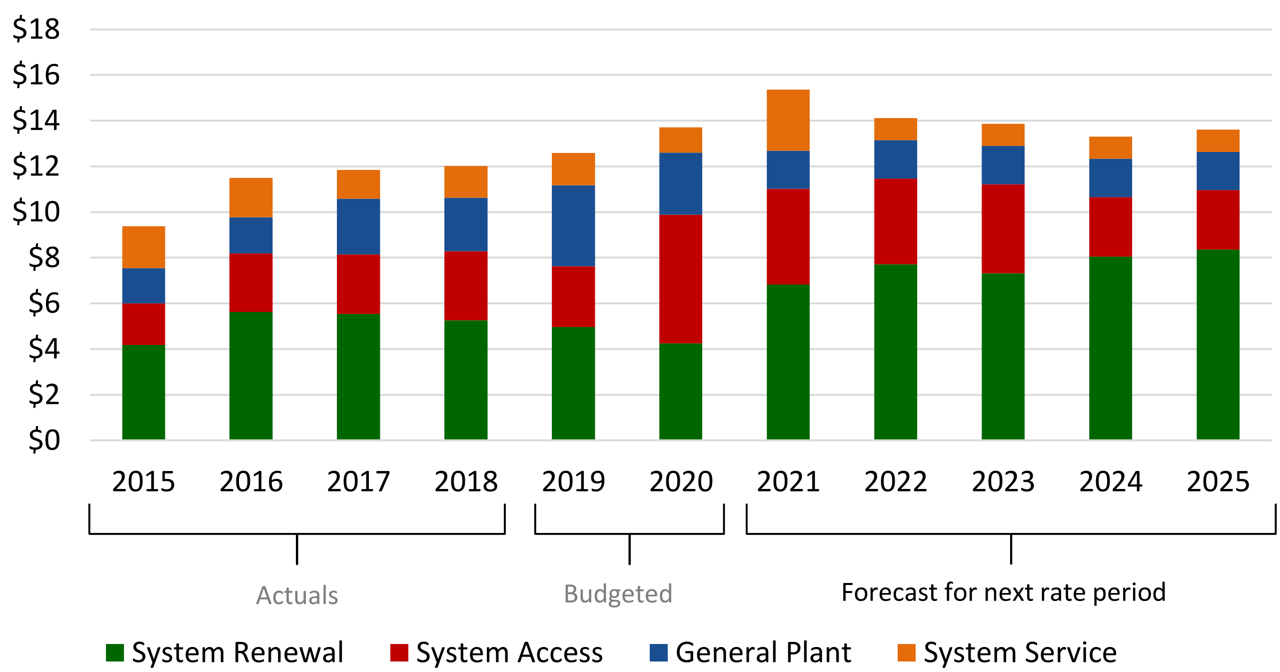
Niagara Peninsula Energy Background

Pacing Capital Investments

The overall amount NPEI invests in capital projects remains generally the same year over year, but what does change is where these investments are made. In some years, when unplanned or unforeseen investments are needed, NPEI will re-allocate funds to make room for these projects within the approved budget. This helps limit the overall amount that the distribution charges fluctuate year-over-year.

The chart below outlines NPEI's spending in past years, and proposed spending for the 5-year period 2021 to 2025.

2015 – 2025 Historical and Forecasted Capital Investments*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

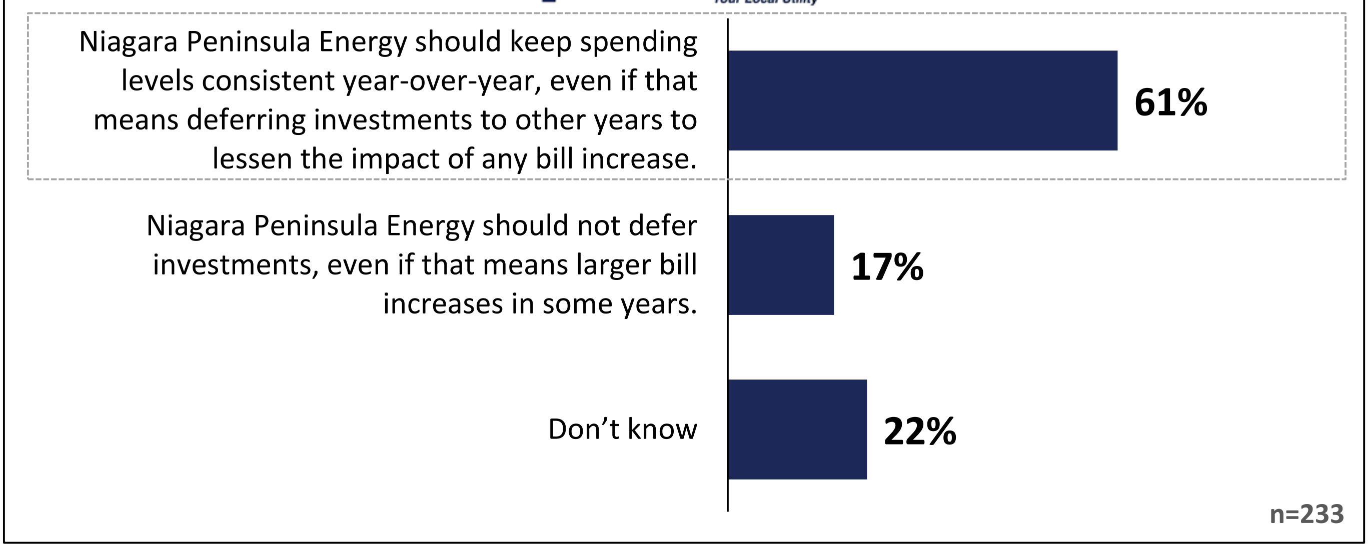
System Access expenditures are budgeted to increase to $5.6M in 2020 to accommodate a number of large commercial customer growth projects as well as municipal road work.

Voluntary Workbook

Approach to Pacing Investments

Residential & Small Business

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to pacing investments?



Q Additional Feedback (Optional)

Additional Feedback (n=22) 91% of respondents did not provide additional feedback	**n-size**
Deferring only increases future prices/invest now in technology and equipment	6
No increase-keep cost low too high already	6
Rate increases should at a reasonable stable rate/ small increases over time when necessary	3
Find efficiencies/cost savings/use profits/capital investments	2
Case by case basis/Prioritize spending on what is needed most	1
Other	4

Niagara Peninsula Energy Background

Mandatory Investments

Federal, provincial, and municipal governments as well as regulators set requirements and standards that NPEI must satisfy. Mandatory investments can be broken down into three categories:

- **Connecting customers**: This includes connecting customers to the grid when a new home or building is constructed or modified.
- **Moving equipment**: This includes moving equipment like poles and cables for road widening.
- **Mandated obligations**: This includes installing and maintaining customer meters and transferring electricity from the provincial transmission system.

These mandatory investments mean that about **one-in-four dollars (23%)** of your distribution rates over the past five years have not been available for other non-mandatory investments. Looking forward to the 2021-2025 period, NPEI forecasts a similar level of mandatory investments, driven largely by:

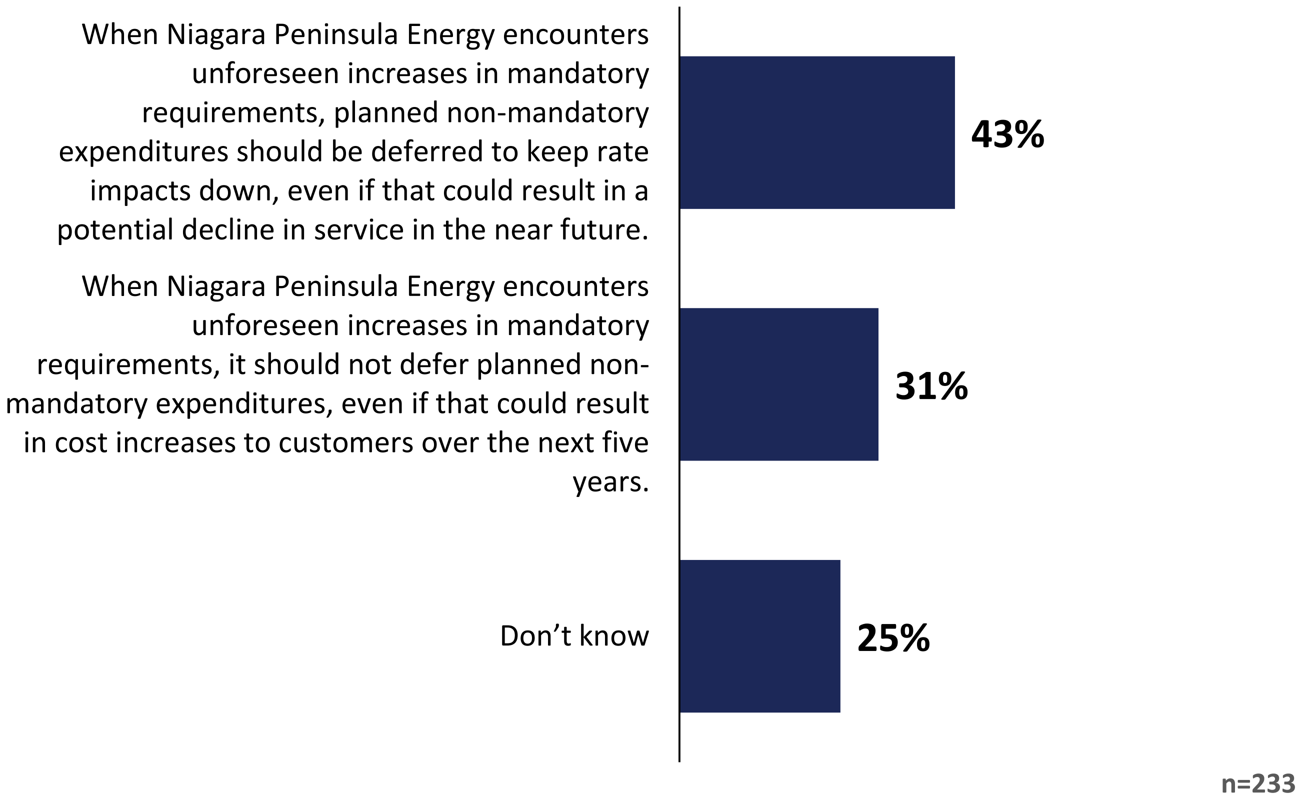
- **Preparing to connect the new Niagara South hospital;**
- **Work to accommodate the 2021 Canada Summer Games in the Niagara Region, and;**
- **Work to accommodate growth and future electricity capacity needs.**

Voluntary Workbook

Approach to Mandatory Investments

Residential & Small Business

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to mandatory and non-mandatory spending?



Q Additional Feedback (Optional)

Additional Feedback (n=18) 92% of respondents did not provide additional feedback	**n-size**
Unforeseen increases should not be encountered/should already be in budget	4
Case by Case basis/New developers/builders/Canada Games/Government- should fund costs	4
Increase within reason when expenditures are necessary/Balance over 5 years	4
Keep rates low/Cost is already to high-no increase	1
Cut back on salaries/operating costs	1
Other	4

Making Choices (1 of 7)

Overhead Pole Replacement

A recent asset health condition assessment shows that **575 or approximately 3%** of the poles in NPEI's distribution system are in *poor* or *very poor* condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a car accident.

On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period.

NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

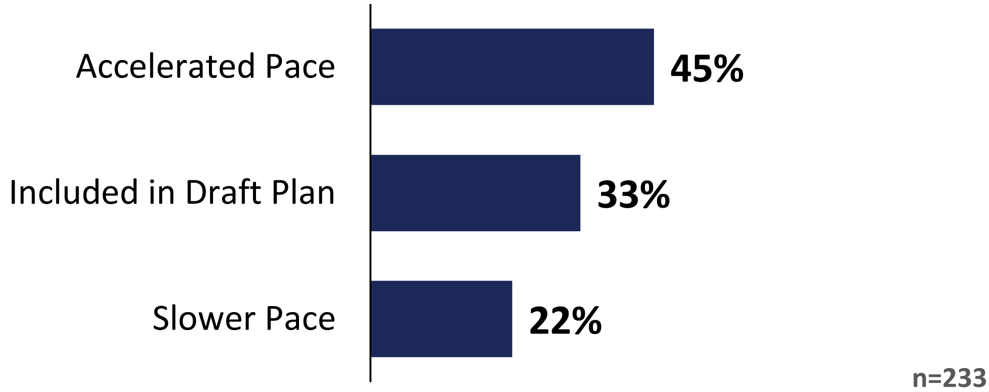
Option	Poles Replaced	Expected Outcome
Accelerated Pace ***<u>Additional</u>*** *$0.03 per month annually ($0.36 more per year)*	1,000 by 2025 (200 per year)	Address the very poor and some of the poor condition poles identified in the Asset Condition Assessment.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	500 by 2025 (100 per year)	Address most of the very poor condition poles identified in the Asset Condition Assessment and annual pole inspections by 2025.
Slower Pace ***<u>Decrease</u>*** *of $0.01 per month annually ($0.12 less per year)*	250 by 2025 (50 per year)	Address only the poles in need of immediate replacement, as identified in the annual pole inspection report.

Voluntary Workbook

Overhead Pole Replacement

Residential & Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=21) 91% of respondents did not provide additional feedback	**n-size**
Bury lines/better to replace with underground lines	5
Cost acceptable	3
Issue due to poor management/maintenance should have been ongoing	3
Be proactive/pay now to save later/costs will only increase	2
Replace as necessary/most urgent first/my street first	2
Replace within budget/no increase to consumer	2
Reliability/safety outweighs cost	1
Investigate/Invest in new pole technology	1
Information misleading/skeptical about figures/inspection criteria	1
None	1

Making Choices (2 of 7)

Overhead transformer replacement

Transformers are a critical piece of distribution equipment that reduce voltage from the higher levels that are more efficient to move electricity long distances to lower levels that are safer to connect to homes and businesses. They are typically either located on the ground, in underground vaults, or attached to distribution poles

A recent asset health condition assessment shows that **1,251 or approximately 21%** of the overhead transformers in NPEI's distribution system are in poor or very poor condition.

Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances.

However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses.

NPEI is proposing a new program to proactively replace **250 of the 677 or 37%** of the overhead transformers identified as very poor condition before they fail over the course of the next five years.

As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

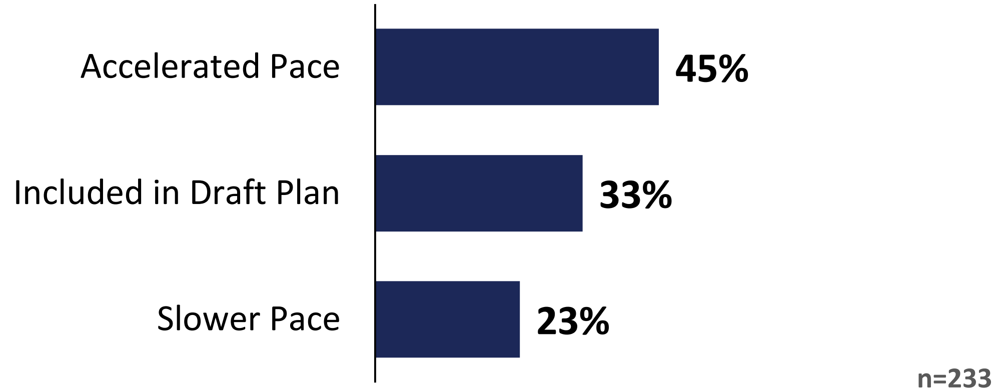
Option	Transformers Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	375 by 2025 (75 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	250 by 2025 (50 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	125 by 2025 (25 per year)	Address only the worst of the polemount transformers identified as very poor in the Asset Condition Assessment report.

Voluntary Workbook

Overhead transformer replacement

Residential & Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=16) 93% of respondents did not provide additional feedback	**n-size**
Issue due to poor management/maintenance should have been ongoing	4
Replace within budget/find efficiencies/no increase to the consumer	4
Replace as necessary/most urgent/poor transformers first	3
Cost acceptable/negligible	2
Replace with underground/more secure alternative	2
Be proactive/pay now to save later/costs will only increase	1

INNOVATIVE RESEARCH GROUP

Making Choices (3 of 7)

Converting Outdated Underground Kiosk Transformers

NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program has been pushed off, and today, there remains 75 transformers in need of replacement.

NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.

Option	Transformers Installed	Expected Outcome
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	55 by 2025 (11 per year)	Work towards eliminating all old installations over the next 7 years.
Reduced Pace ***Decrease** of $0.02 per month annually ($0.24 less per year)*	25 by 2025 (5 per year)	Work towards eliminating all old installations over the next 15 years.
Slower Pace ***Decrease** of $0.03 per month annually ($0.36 less per year)*	10 by 2025 (2 per year)	Work towards eliminating all old installations over the next 35 years.

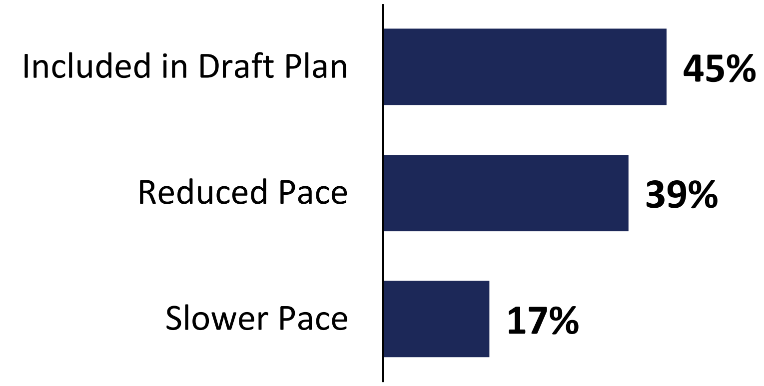
Voluntary Workbook

Converting Outdated Underground Kiosk Transformers

Residential & Small Business

Q Which of the following options do you prefer?

niagara peninsula energy inc. Your Local Utility



n=233

Q Additional Feedback (Optional)

Additional Feedback (n=11) 95% of respondents did not provide additional feedback	n-size
Replace within budget/find efficiencies/no increase to the consumer	4
Reliability/safety outweighs cost	2
Be proactive/	2
Replace as necessary/most urgent/outdated first/run to fail	2
Issue due to poor management/maintenance should have been ongoing	1

INNOVATIVE RESEARCH GROUP

Making Choices (4 of 7)

Underground cable replacement

Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years.

Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses.

Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.

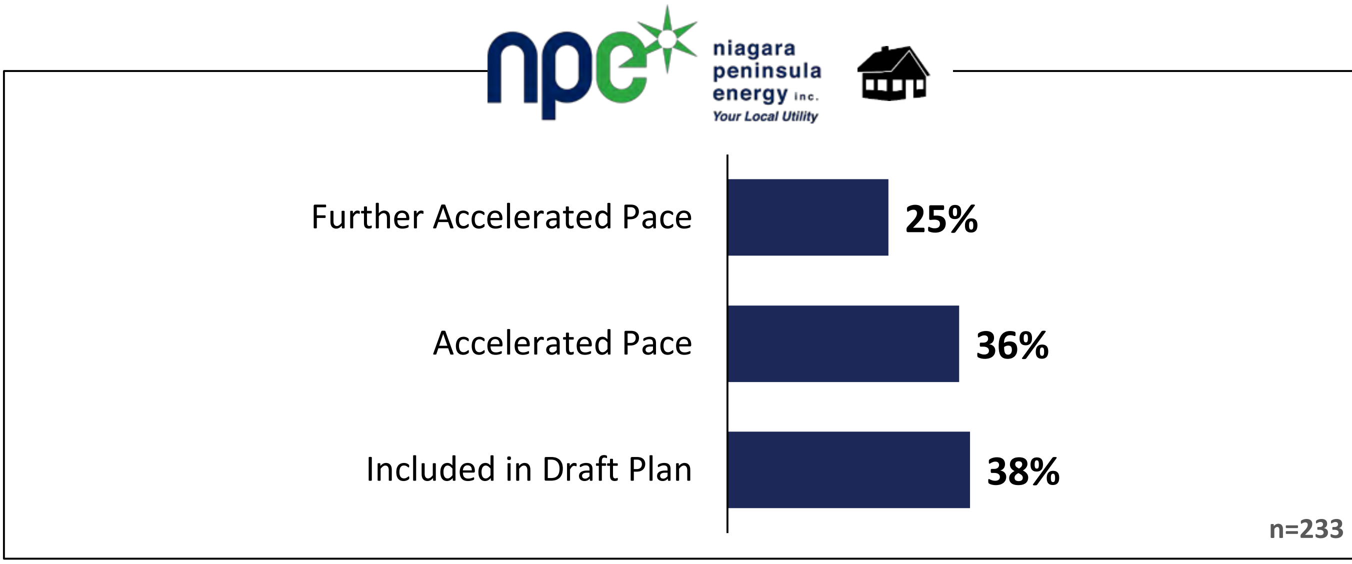
Option	Km of cable installed	Expected Outcome
Further Accelerated Pace ***Additional*** *$0.13 per month annually ($1.56 more per year)*	24 km by 2025 (4.8 km per year)	Proactively replace more of the cables identified as past end of life in the Asset Condition Assessment Report.
Accelerated Pace ***Additional*** *$0.06 per month annually ($0.72 more per year)*	12 km by 2025 (2.4 km per year)	Proactively replace some of the cables identified as past end of life in the Asset Condition Assessment Report.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	2 km by 2025 (0.4 km per year)	Replace cables past end of life as other work is being completed on associated switchgear or riser poles.

Voluntary Workbook

Underground cable replacement

Residential & Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=10) 96% of respondents did not provide additional feedback	**n-size**
Be proactive/pay now to save later/costs will only increase	2
Reliability/safety outweighs cost	2
Replace within budget/no increase to consumer/cash grab	2
Bury lines/better to replace with underground lines	1
Issue due to poor management/maintenance should have been ongoing	1
Improve cable assessments/more investigation required	1
Other	1

Subdivision underground rehabilitation

71 of the subdivisions in NPEI's service territory were constructed with **direct buried cable** which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier.

While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life.

In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs.

In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed.

Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time.

Between 2021 and 2025, NPEI is proposing a new program that will proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.

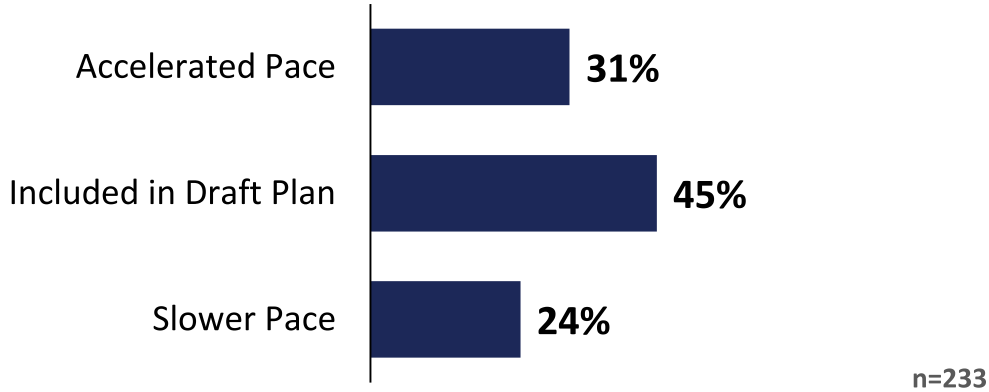
Option	Km of vault installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.02 per month annually ($0.24 more per year)*	30 km by 2025 (6 km per year)	Install 6 km of ducts or approximately four subdivisions per year.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	15 km by 2025 (3 km per year)	Install 3 km of ducts or approximately two subdivisions per year.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	7.5 km by 2025 (1.5 km per year)	Install 1.5 km of ducts or approximately one subdivision per year.

Voluntary Workbook

Subdivision underground rehabilitation

Residential & Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=9) 96% of respondents did not provide additional feedback	**n-size**
Charge new developments/Only affected customers should pay	3
Issue due to poor management/maintenance should have been ongoing	2
Need more information	1
Replace as necessary/most urgent first	1
Replace within budget/no increase to consumer	1
Information misleading/skeptical about figures/inspection criteria	1

INNOVATIVE RESEARCH GROUP

Making Choices (6 of 7)

Overhead rebuilds

Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system.

A recent asset health condition assessment identified a total of **60 areas** within NPEI's service territory that require complete overhead rebuilds**.** Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section.

This program is intended to contribute to the "betterment" of the overhead system by;

- Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and;
- Improving system aesthetics with new and taller poles.

On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's current approach would rebuild **40 out of 60 areas** in the 2021 to 2025 period.

NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.

Option	Overhead rebuilds	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	61 km by 2025 (12.2 km per year)	Rebuild 12.2 km per year or approximately 10 projects per year
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	48.5 km by 2025 (9.7 km per year)	Rebuild areas with assets that have been identified as very poor in Asset Condition Assessment. Rebuild 9.7 km per year or approximately 8 projects per year
Slower Pace ***Decrease*** *of $0.03 per month annually ($0.36 less per year)*	36 km by 2025 (7.2 km per year)	Rebuild 7.2 km per year or approximately 6 projects per year

Voluntary Workbook

Overhead rebuilds

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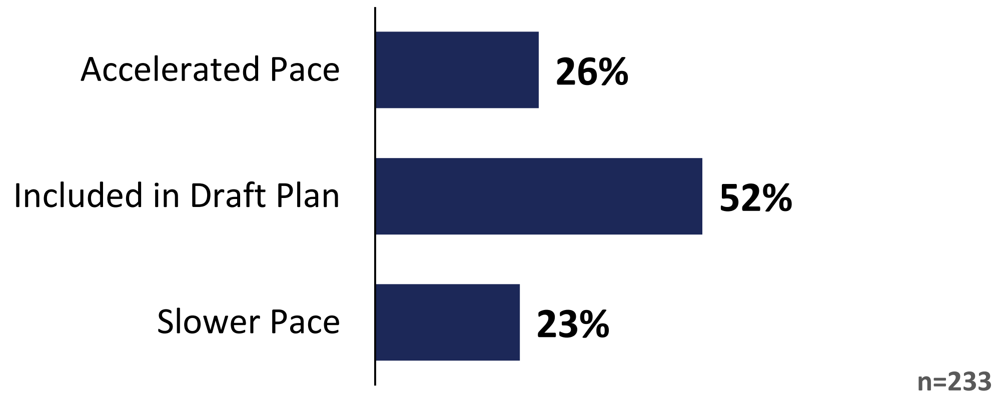
Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=13) 94% of respondents did not provide additional feedback	**n-size**
Replace within budget/find efficiencies/no increase to consumer	4
Bury lines/better to replace with underground lines	3
Coordinate with other services/find other revenue streams/charge new developments	3
Improve infrastructure/protect from animals	3

Making Choices (7 of 7)

Grid modernization

New technology has changed the way that NPEI can manage and monitor the distribution system.

Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory.

This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event.

On average, since 2014, NPEI has installing approximately two remote devices per year, with focus on more rural, lower density areas. That said, there is an opportunity to install this monitoring and control equipment more quickly or slowly.

Option	Devices installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	20 devices (4 per year)	NPEI to double installation rate to four devices per year.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	10 Devices (2 per year)	Remain at current installation pace of two devices per year. Install new devices to expand NPEI's Smart Grid network. These devices provide better monitoring capability on the system, which leads to improved restoration times during outages.
Slower Pace ***Decrease*** *of $0.005 per month annually ($0.06 less per year)*	5 Devices (1 per year)	NPEI to cut rate of installation in half to one device per year.

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Grid modernization

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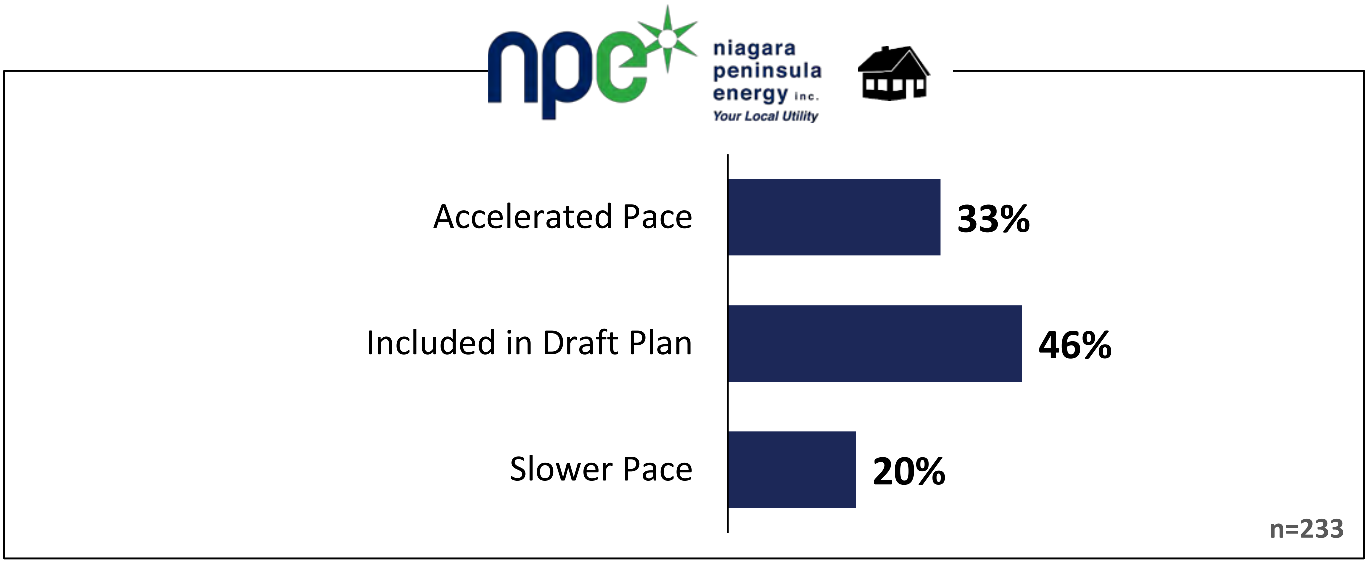
Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

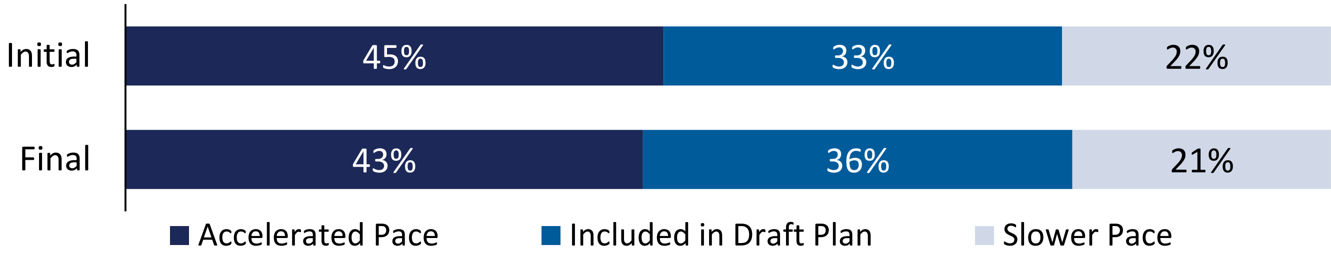
Additional Feedback (n=11) 95% of respondents did not provide additional feedback	**n-size**
Be proactive/pay now to save later/costs will only increase	2
Keeping consumer costs low should be a priority/cost already high	2
Cost acceptable	1
Only affected customers should pay	1
Reliability/safety outweighs cost/protect grid/upgrade	1
Replace within budget/find efficiencies	1
Other	2
None	1

Voluntary Workbook

Change in Initial vs. Final Response by Project

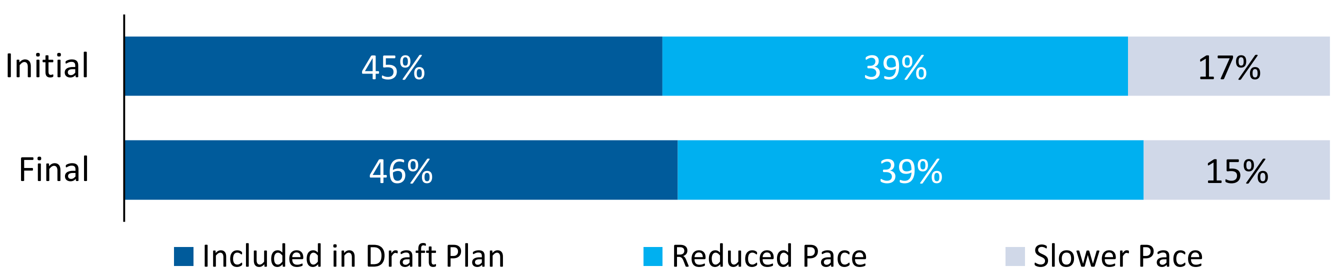
Residential & Small Business

Q Overhead Pole Replacement

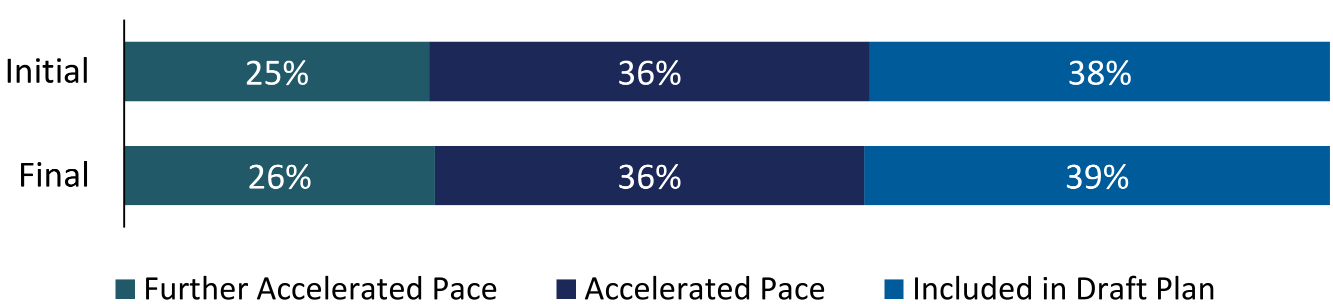


Q Overhead Transformer Replacement

Q Converting Outdated Underground Kiosk Transformers



Q Underground Cable Replacement

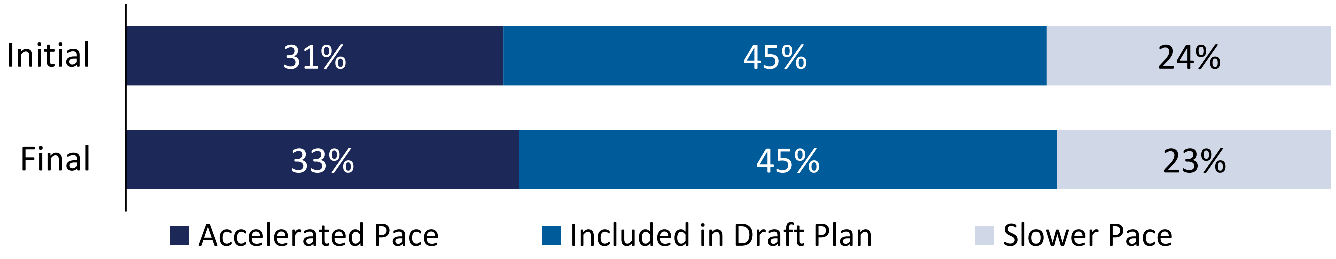


Voluntary Workbook

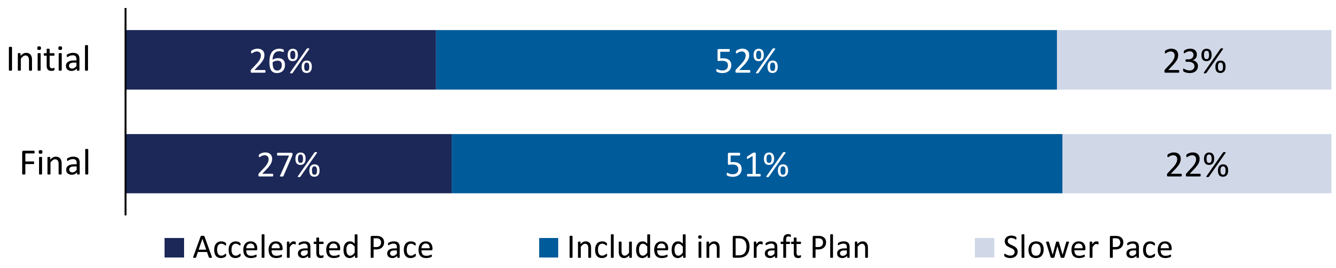
Change in Initial vs. Final Response by Project

Residential & Small Business

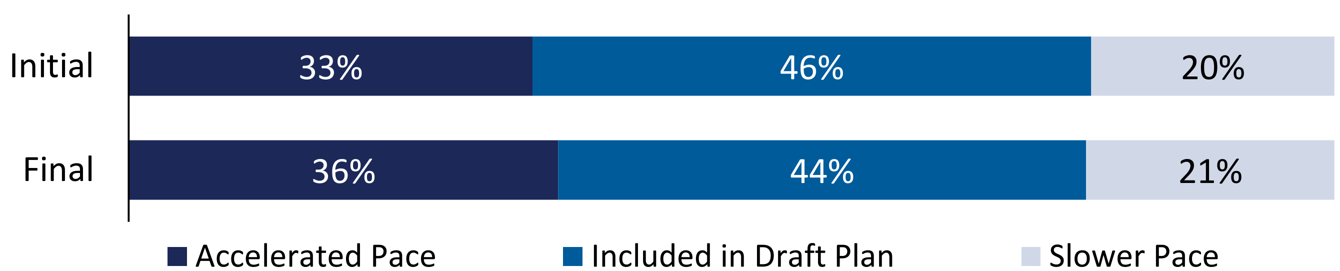
Q Subdivision Underground Rehabilitation



Q Overhead Rebuilds



Q Grid Modernization



Impact of Choices

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Again, it is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $2.53 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by $4.29.
- As a result, the distribution charges on the typical residential customer's monthly bill would increase from $33.51 in 2020 to $37.80 by 2025.

Estimated Typical Residential Annual Increase in Monthly Bill (5 year forecast)

	Year	Average Residential Bill	Distribution Portion of Bill	Incremental Rate Change	% Change * (on distribution portion of bill)
Current Rate	**2019**	$113.32	$33.11		
Budgeted Rate	**2020**	$115.03	$33.51	$0.40	1.21%
Forecast for next rate period	**2021**	$116.33	$36.04	$2.53	7.55%
	2022	$118.08	$36.47	$0.43	1.20%
	2023	$119.85	$36.91	$0.44	1.20%
	2024	$121.65	$37.35	$0.44	1.20%
	2025	$123.47	$37.80	$0.45	1.20%
				$4.29	

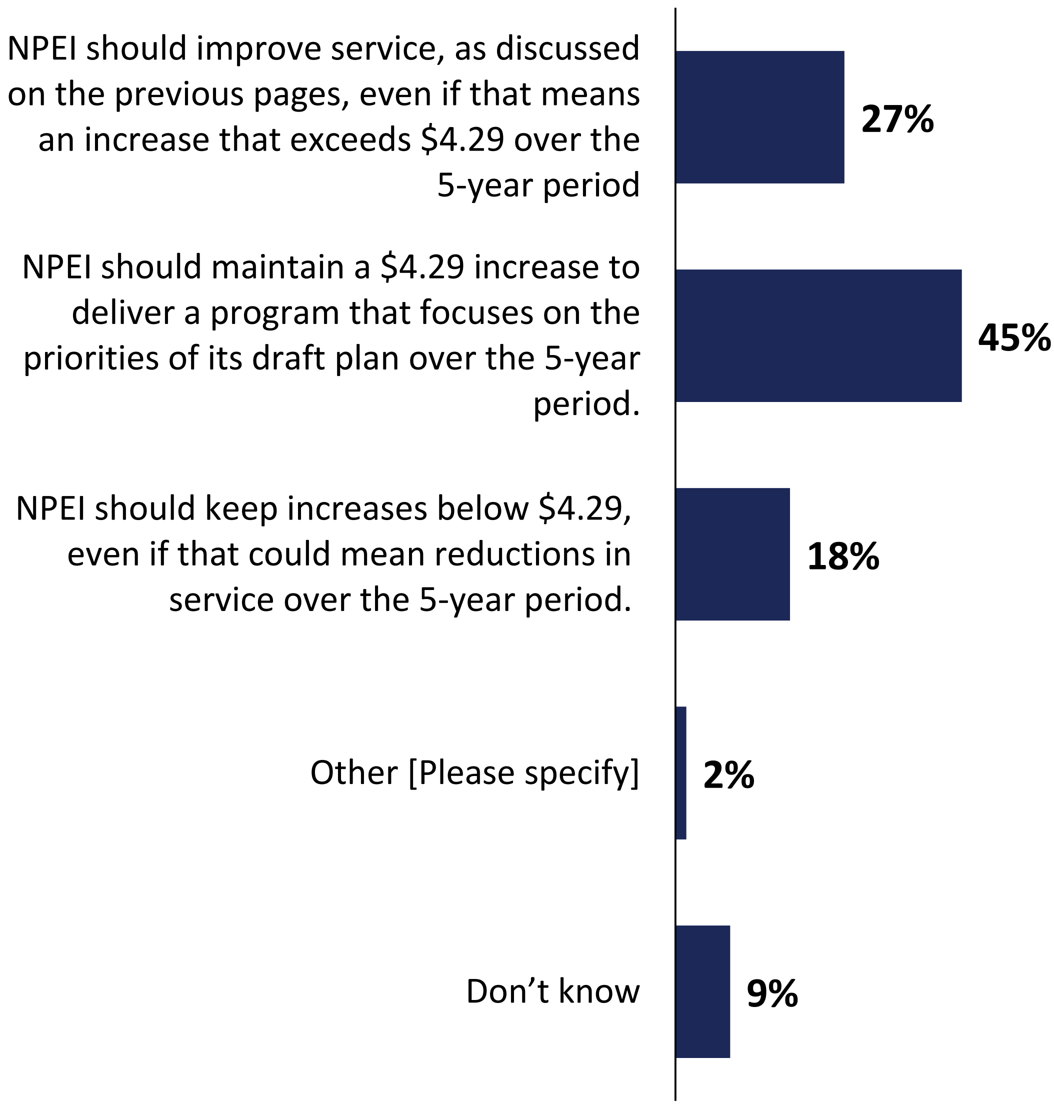
*** These estimates are preliminary, and are subject to your feedback as the business plan is finalized .**

Voluntary Workbook

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Residential &
Small Business

Q Considering what you know about Niagara Peninsula Energy's draft plan – which would see the typical residential customer's distribution portion of their bill increase by $4.29 over the 5-year period – which of the following best represents your point of view?



n=233

Voluntary Workbook

Final Comments

Q

Thinking about your answer to the previous question, why do you feel that NPEI should take that approach over the 2021-2025 period?

Final Comments (n=65) 72% of respondents did not provide additional feedback	**n-size**
Proactive approach-Pay now to ensure proper maintenance and prevent higher cost in the future	20
rates are high enough already/no increase	17
Increase is reasonable -taking affordability into account	16
Unforseen issues and maintenace should have already been planned in current budget	2
look for efficiencies to offset cost	2
Prioritize necessary improvements /repair as needed	1
Find alternative funding-Customers should not bear cost increase	1
Balance approach	1
Other	4
None	1

Q

Do you have any final comments regarding NPEI or the customer engagement that you just completed?

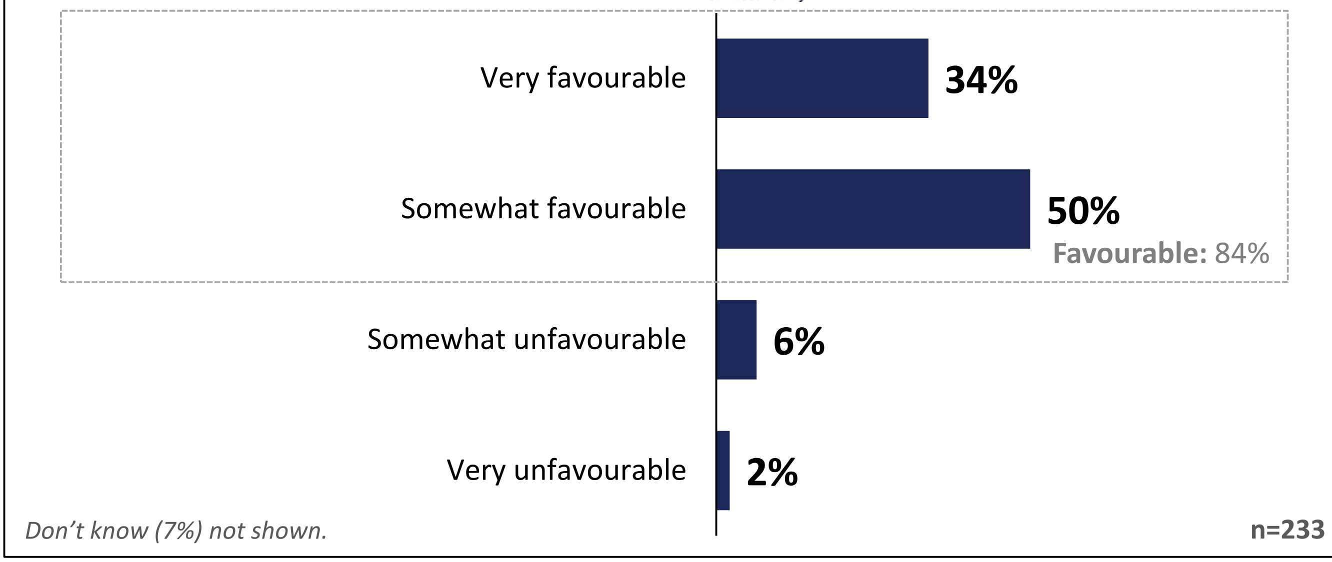
Final Comments (n=28) 88% of respondents did not provide additional feedback	**n-size**
Positive - General NPEI/Survey/ asking for Customer input/informative	10
Cost issues/delivery fees/High rates/keep cost low	7
Invest now to avoid higher cost in the future/Maintain and repair accordingly	5
Transparency-future planning	1
Other	1
None	4

Voluntary Workbook

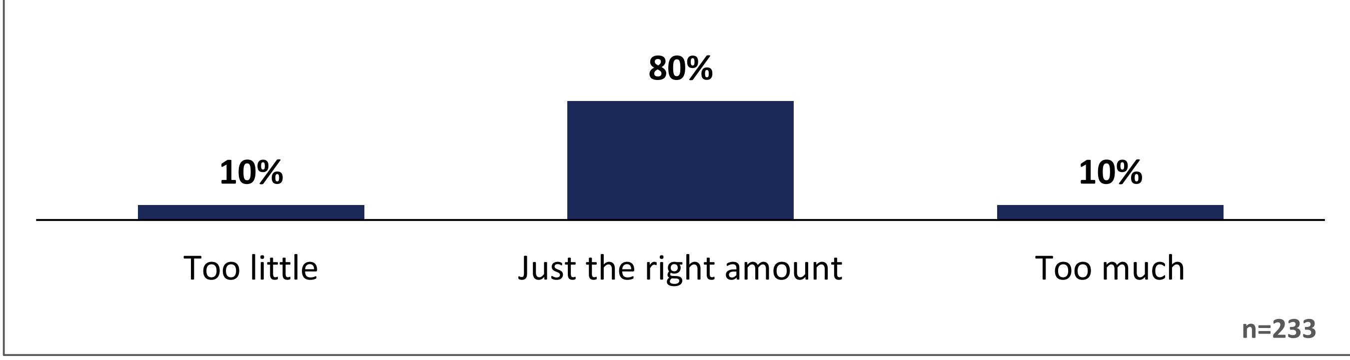
Final Thoughts: Workbook Diagnostics

Residential & Small Business

Q **Overall Impression**: Overall, did you have a favourable or unfavourable impression of the consultation you just completed?



Q **Volume of Information:** In this consultation, do you feel that NPEI provided too much information, not enough, or just the right amount?



Voluntary Workbook

Content Covered and Unanswered Questions

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Q Was there any content missing that you would have liked to have seen included in this consultation?

Content Covered (n=233)	n-size
None	205
Operating costs/Executive-Salaries/bonuses	8
Cost/delivery fees/High rates/keep cost low	6
transparency/breakdown of cost allocation	4
Alternative energy sources/Turbine/Solar/renewable	2
Going underground/bury lines/cost	1
More information on system reliability aging infrastructure/preventative measures	1
Other	6

Q Is there anything that you would still like answered?

Unanswered Questions (n=233)	n-size
None	218
Cost issues/delivery fees/High rates/keep cost low	4
Operating costs/Executive-Salaries/bonuses	3
Consultations with Customers/ updates as to what course of action and plan will be taken	1
Transparency-Cost allocation	1
Infrastructure repairs/ updates	1
Positive - General NPEI/Survey/ asking for Customer input/informative	1
Other	4

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Customer Engagement Workbook

Residential Workbook

November 2019

STRICTLY PRIVILEGED AND CONFIDENTIAL

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About this Consultation

Welcome to Niagara Peninsula Energy's Customer Engagement!

Niagara Peninsula Energy (NPEI) needs your input on choices that will impact the services you receive and the rates that you pay.

- **NPEI** is developing its investment plan for 2021 to 2025. This plan will determine the investments NPEI will make in equipment and infrastructure; the services it provides; and the rates you pay.
- As **NPEI** plans for the future, they want to ensure their business decisions are aligned with customers priorities, preferences, and needs.
- Throughout this survey, information will be provided in an effort to give you more background on which to base your responses.
- While responding to the following questions, remember that there are no wrong answers, and that your individual responses will remain anonymous.
- This customer engagement will take approximately 25-35 minutes to complete, depending on the level of feedback you wish to provide. Your progress will be saved as you move through the workbook, meaning you can leave and return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired NPEI to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one (1) $500 cash prize.

About this Consultation

Thank you for your interest in being a part of Niagara Peninsula Energy's customer engagement.

If you are reading this on a smaller mobile device, you may want to consider accessing the survey from a tablet, desktop or laptop instead so that it is easier for you to read.

Would you like to complete this survey on behalf of your business/organization, or your home?

o Business/organization

o Home

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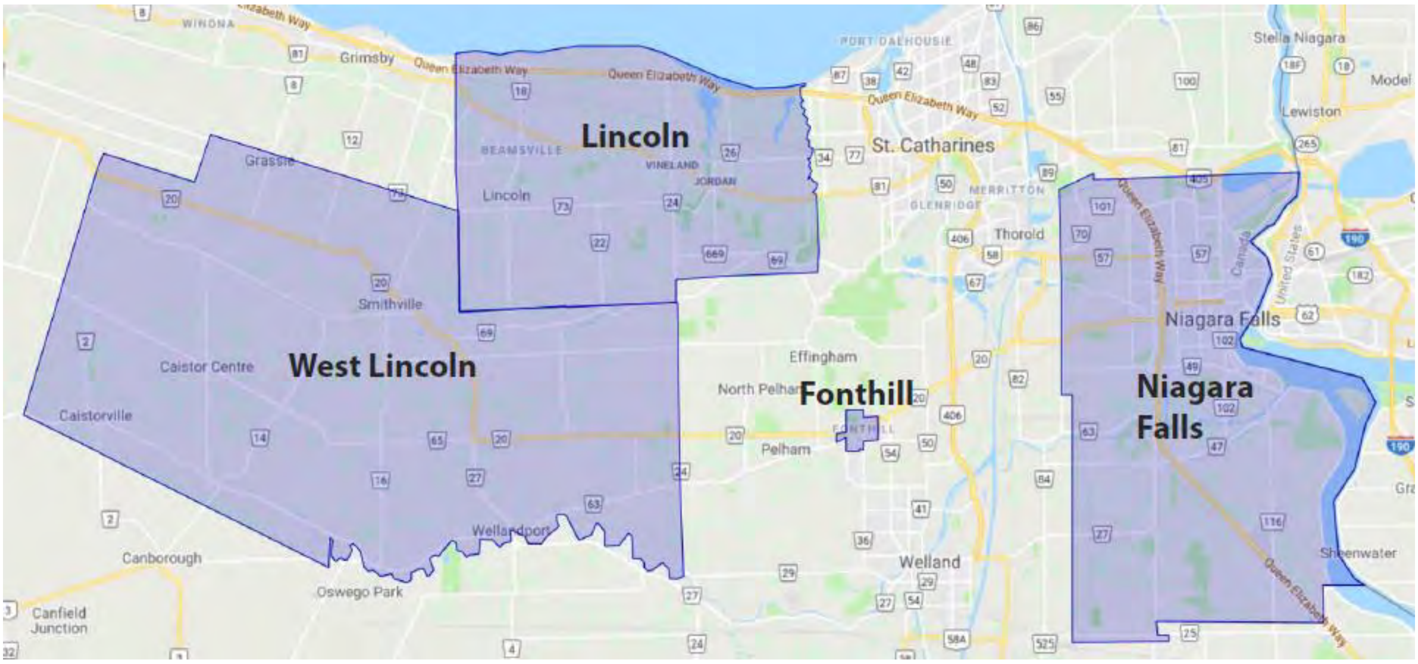
Electricity 101

Who is Niagara Peninsula Energy?

NPEI provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham, and Township of West Lincoln.

- NPEI serves an area of approximately 827 square kilometers and a customer base of approximately 55,600 residential and business customers, containing a mix of urban and rural electrical distribution.
- NPEI is jointly owned by the municipalities it services.
- NPEI manages all aspects of the electricity distribution business and is regulated by the Ontario Energy Board (OEB).
- As a local distribution company (LDC) and regulated entity, NPEI applies for, and receives approval from the regulator to charge for its services.



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Electricity 101

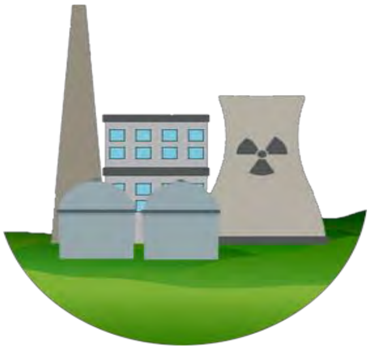
Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

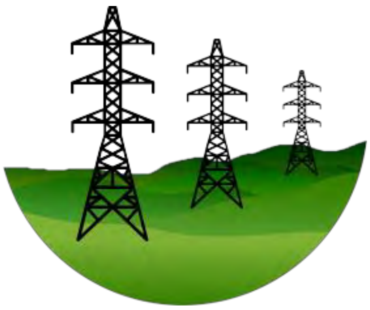
Ontario's electricity is generated using a mix of nuclear, gas-fired, and water power (hydro), as well as biomass and renewable sources such as wind and solar technology. In Ontario, a number of companies own these generating stations but approximately half of the electricity is generated by Ontario Power Generation. The Independent Electricity System Operator (IESO) balances the supply of, and demand for, electricity on a second-by-second basis and directs its flow across the high-voltage transmission lines.



Transmission

How electricity travels across Ontario

Once generated, electricity must be transported to electrical substations across the province. Due to the large amount of power and long distances, transmission normally takes place at high voltages with the lines suspended on large, steel towers. The province has more than 30,000 kilometres of 'electricity highway', most of which is owned and operated by Hydro One.



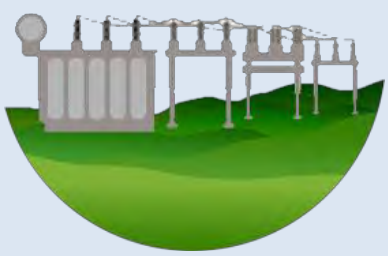
Local Distribution

How electricity is delivered to the end-consumer

NPEI is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, NPEI delivers electricity to approximately 55,600 residential and business customers.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.



npe niagara peninsula energy Inc. *Your Local Utility*

Q1. Before this survey, how familiar were you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar at all
- ☐ Don't know

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Electricity 101

How much of my electricity bill goes to Niagara Peninsula Energy?

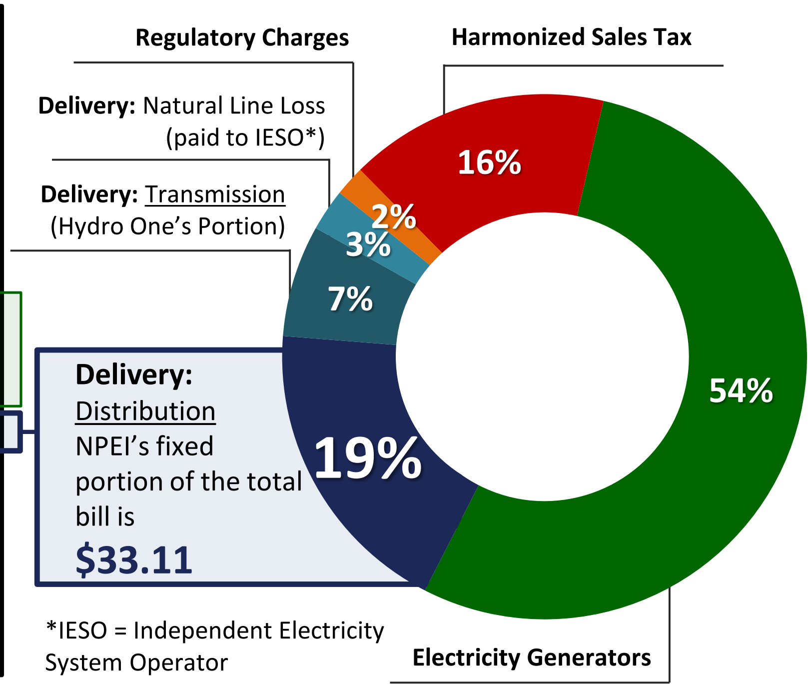
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge.
- Distribution makes up about **19%** of the typical residential customer's bill.
- For residential customers, NPEI's portion of the delivery line on the bill is fixed and does not change based on the amount of electricity you use.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

NPEI Sample Monthly Bill*
(Based on monthly usage of 700 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Off-Peak @ 10.1 ¢/kWh	45.25
Mid-Peak @ 14.4 ¢/kWh	18.14
On-Peak @ 20.8 ¢/kWh	26.21
Delivery	46.85
Regulatory Charges	3.11
Total Electricity Charges	**$139.56**
HST	18.14
Ontario Electricity Rebate*	(-$44.38)
Total Amount	**$113.32**



*IESO = Independent Electricity System Operator

* As of November 1, 2019. Chart is based on total bill amount after applying the Ontario Electricity Rebate.

Q2. Thinking specifically about the services provided to you and your community by Niagara Peninsula Energy, overall, how satisfied or dissatisfied are you with the services that you receive?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

Q3. Before this survey, how familiar were you with the amount of your electricity bill that went to Niagara Peninsula Energy?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar
- ☐ Don't know

Q4. Is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to you?

Niagara Peninsula Energy Background

Building Niagara Peninsula Energy's draft plan

NPEI has put together its draft business plan based on the information and input from various sources, such as:

- **Legal and regulatory** requirements by continuing to meet its obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected through both ongoing dialogues and specific engagements, such as this.

There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their businesses and serve their customers.

- **Policy**: The Ontario Ministry of Energy, Northern Development and Mines (MNDM) creates energy policy for the province.
- **Regulation**: The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.
- **Operations and Planning**: The Independent Electricity System Operator (IESO) manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

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Niagara Peninsula Energy Background

How did customer feedback shape Niagara Peninsula Energy's draft plan?

NPEI is placing more emphasis on incorporating customer feedback into the planning process than ever before.

NPEI engages with its customers both in day-to-day interactions and in a variety of customer engagement activities. These interactions help identify customer needs and preferences, and inform how the utility plans for the future.

This past summer, NPEI engaged with **thousands of residential and business customers** from across its service territory – both in person and through telephone and online surveys.

What did NPEI hear from customers like yourself?

1. The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates".

2. Among competing outcomes, **price**, **reliability**, and **finding internal cost efficiencies** are the top three priorities for both residential and small business customers.

3. While keeping price at a reasonable and affordable level is an important priority, many customers feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Considering this feedback, as well as the information and inputs discussed on the previous page, NPEI has developed a draft plan that is responsive to:

1. Legal requirements by continuing to meet its obligations, including safety and reliability;

2. A transformer station upgrade to accommodate the new Niagara South Hospital and future surrounding growth.

3. Mandatory service connections to accommodate new customers and customer-required upgrades, of which NPEI does not have control over how and when these costs are incurred.

4. Customer feedback by:

   a) Keeping distribution price increases as low as possible;

   b) Maintaining long-term performance for customers experiencing average or better service;

   c) Improving service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,

   d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

Niagara Peninsula Energy Customer Engagement
Planning for the Future: 2021-2025 Rate Application

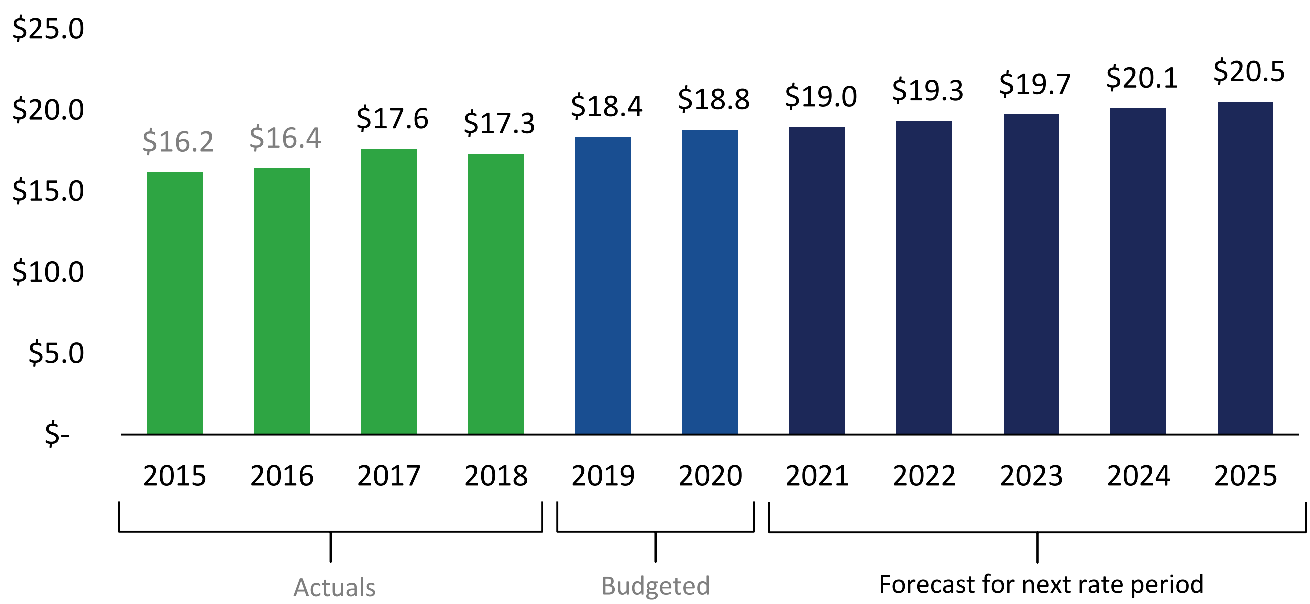
Niagara Peninsula Energy Background

Operating Expenses

In this section, we want to focus on operating expenses and how NPEI compares to its peers.

NPEI's operating budget covers recurring expenses, such as the maintenance of poles, wires, transformers, fleet and buildings as well as proactive maintenance programs such as tree trimming, and payroll for employees. Meter reading, postage, cyber security and hardware/software maintenance expenses are billing and customer service-related expenses. The proposed 5-year plan, between 2021 and 2025, would see NPEI spend an estimated total of $98.7 million on operations.

NPEI's Current and Forecasted Operating Expenses, per Year (Millions)*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI's **operating costs** are benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, NPEI's operating costs per customer was **$311.67**, which is slightly more than some, while less than both Hydro One and Canadian Niagara Power.

2018 Operating & Maintenance and Administration (OM&A) Per Customer ($)

The diverse geographical nature of NPEI's service territory, which is a mix of urban and rural communities is a large consideration/driver of these OM&A costs. In some parts of the service territory, there may be less than 30 customers per kilometer of line. Despite low density, these lines still require the same level of ongoing maintenance, including tree trimming and other expenses that contribute to operating the system; thereby resulting in a higher cost per customer.

Niagara Peninsula Energy Background

Operating Expenses

Recall, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge NPEI's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found at oeb.ca/participate.

This customer engagement however, is focused on capital investments.

Detailed discussion of NPEI's operating budget is left to experts from the OEB and intervenors in the formal rate application review; this workbook focuses on collecting your view on competing trade-offs in capital investments.

Q5. Does leaving the detailed discussion about Niagara Peninsula Energy's operating budget to experts from the OEB and intervenors seem like the right approach or wrong approach to you?

- ☐ Definitely the right approach
- ☐ Probably the right approach
- ☐ Probably the wrong approach
- ☐ Definitely the wrong approach
- ☐ Don't know enough to say

Additional Feedback (Optional)

Q6. [If wrong approach] And why do you say leaving the detailed discussion about NPEI's operating budget to the OEB and intervenors is the wrong approach? [OPEN]

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Niagara Peninsula Energy Background

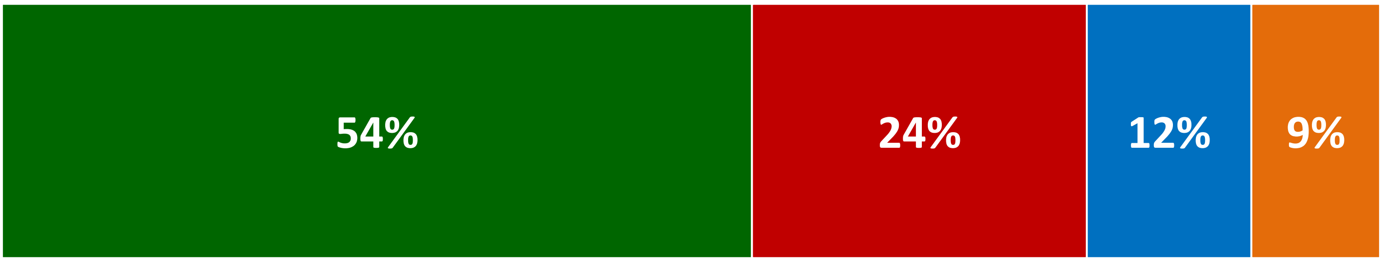
Capital Investments

NPEI's **capital budget** covers items that, once purchased, have lasting benefits over many years. Year-over-year, regardless of external drivers, NPEI will need to make investments in the core distribution system, including poles, wires, cables and transformers.

Based on initial customer input and the approach outlined previously, NPEI believes the capital expenditure required to address system renewal, maintain system reliability and safety, and invest in other infrastructure priorities between 2021 and 2025 is estimated to be **$70.3 million**.

NPEI classifies the costs of four types of capital investment between 2021 and 2025. Each of these four investment categories helps NPEI pace and prioritize projects.

2021-2025 Forecasted Capital Investments



System Renewal ($38.2 million)

These projects are a mix of planned end-of-life replacements and emergency replacements.

Projects Include: Replacement of existing overhead wires, poles, and pole mounted transformers, underground cables and transformers and transformer station upgrades.

System Access ($17.1 million)

"Must do" investments that respond to customer requests for new connections or new infrastructure development.

Projects Include: NPEI's share of new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs.

General Plant ($8.4 million)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

Projects Include: Financial and customer IT systems, enhanced cyber security investments, facility renovations, backup generation, and vehicle replacements.

System Service ($6.6 million)

These investments consist of projects that address capacity constraints, improve system reliability and customer service.

Projects Include: Installation of automated switches and system expansion to supply new development.

Niagara Peninsula Energy Background

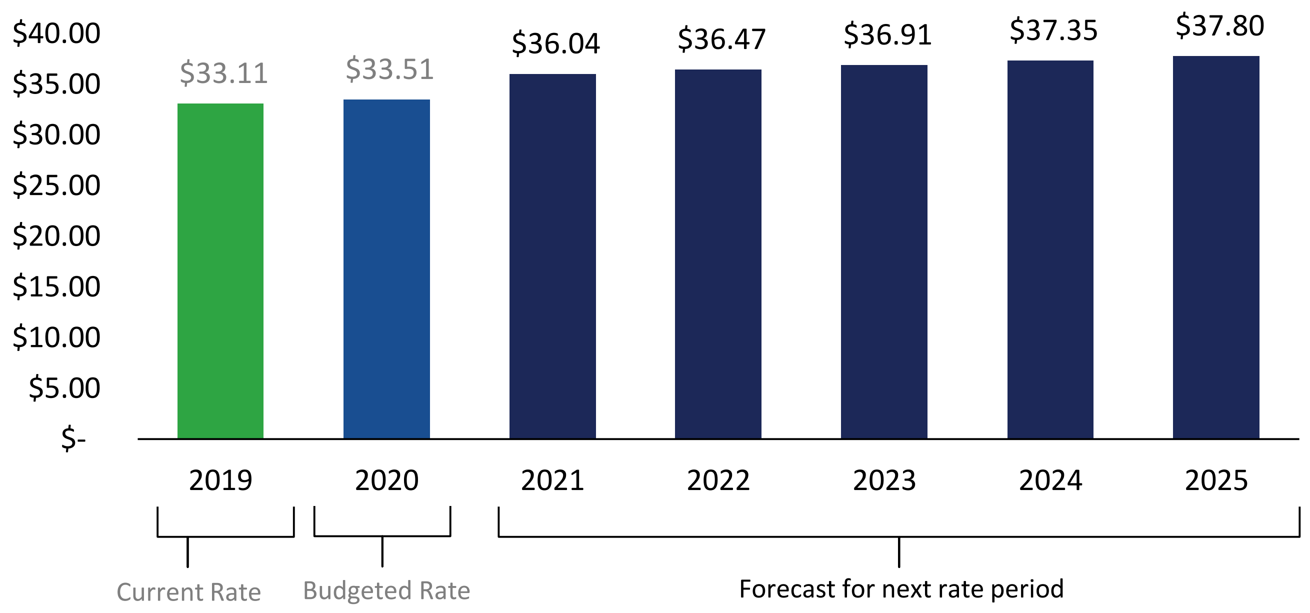
How much will this draft plan cost me?

Remember, the current typical NPEI residential customer's electricity bill is about $113 per month, of which $33.11 goes to NPEI.

It is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $2.53 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by $4.29.
- As a result, the distribution charges on the typical residential customer's monthly bill would increase from $33.51 in 2020 to $37.80 by 2025.

Estimated Residential Monthly Distribution Charge, per Year*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI is looking for your input on its preliminary plan to ensure it is making the spending decisions that matter to you, the customer.

The following sections of this workbook will explore some of the choices Niagara Peninsula Energy needs to make to help finalize its preliminary plan.

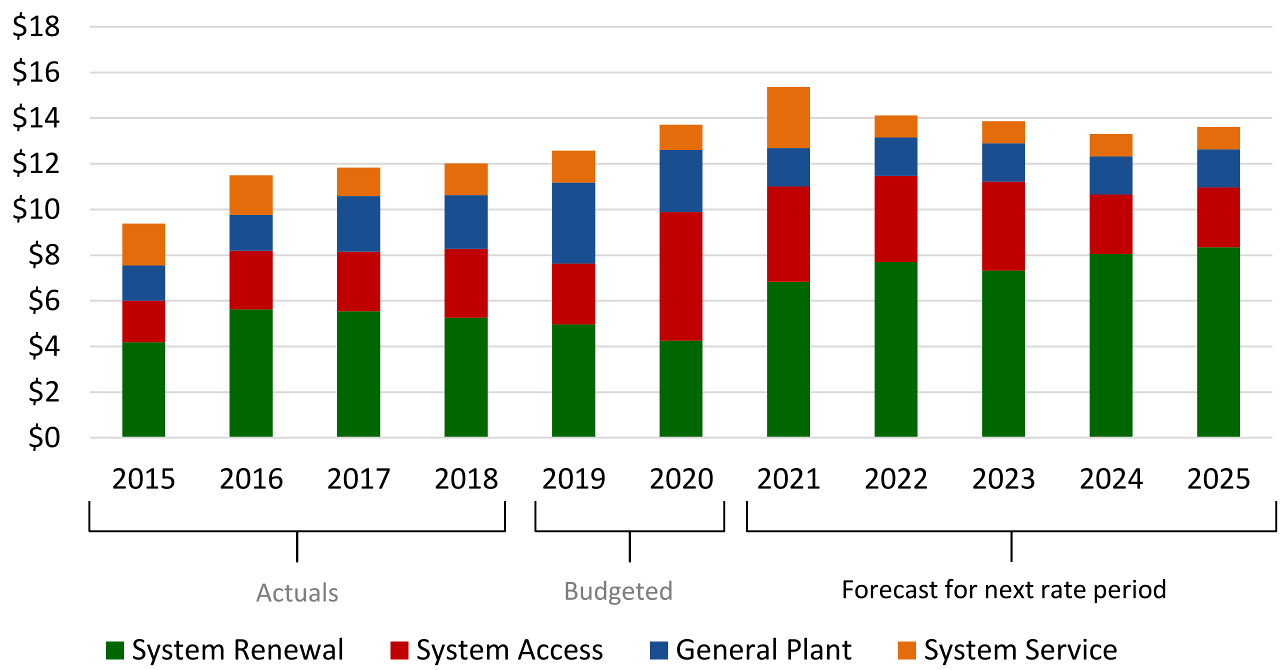
Niagara Peninsula Energy Background

Pacing Capital Investments

The overall amount NPEI invests in capital projects remains generally the same year over year, but what does change is where these investments are made. In some years, when unplanned or unforeseen investments are needed, NPEI will re-allocate funds to make room for these projects within the approved budget. This helps limit the overall amount that the distribution charges fluctuate year-over-year.

The chart below outlines NPEI's spending in past years, and proposed spending for the 5-year period 2021 to 2025.

2015 – 2025 Historical and Forecasted Capital Investments*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

System Access expenditures are budgeted to increase to $5.6M in 2020 to accommodate a number of large commercial customer growth projects as well as municipal road work.

Q7. Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to pacing investments?

- ☐ Niagara Peninsula Energy should keep spending levels consistent year-over-year, even if that means deferring investments to other years to lessen the impact of any bill increase.
- ☐ Niagara Peninsula Energy should not defer investments, even if that means larger bill increases in some years.
- ☐ Don't know

Additional Feedback (Optional)

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Niagara Peninsula Energy Background

Mandatory Investments

Federal, provincial, and municipal governments as well as regulators set requirements and standards that NPEI must satisfy. Mandatory investments can be broken down into three categories:

- **Connecting customers**: This includes connecting customers to the grid when a new home or building is constructed or modified.
- **Moving equipment**: This includes moving equipment like poles and cables for road widening.
- **Mandated obligations**: This includes installing and maintaining customer meters and transferring electricity from the provincial transmission system.

These mandatory investments mean that about **one-in-four dollars (23%)** of your distribution rates over the past five years have not been available for other non-mandatory investments. Looking forward to the 2021-2025 period, NPEI forecasts a similar level of mandatory investments, driven largely by:

- **Preparing to connect the new Niagara South hospital;**
- **Work to accommodate the 2021 Canada Summer Games in the Niagara Region, and;**
- **Work to accommodate growth and future electricity capacity needs.**

Q8. Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to mandatory and non-mandatory spending?

- ☐ When Niagara Peninsula Energy encounters unforeseen increases in mandatory requirements, planned non-mandatory expenditures should be deferred to keep rate impacts down, even if that could result in a potential decline in service in the near future.
- ☐ When Niagara Peninsula Energy encounters unforeseen increases in mandatory requirements, it should not defer planned non-mandatory expenditures, even if that could result in cost increases to customers over the next five years.
- ☐ Don't know

Additional Feedback (Optional)

Making Choices (1 of 7)

Overhead Pole Replacement

A recent asset health condition assessment shows that **575 or approximately 3%** of the poles in NPEI's distribution system are in *poor* or *very poor* condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a car accident.

On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period.

NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Q9. Which of the following options do you prefer?

Option	Poles Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	1,000 by 2025 (200 per year)	Address the very poor and some of the poor condition poles identified in the Asset Condition Assessment.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	500 by 2025 (100 per year)	Address most of the very poor condition poles identified in the Asset Condition Assessment and annual pole inspections by 2025.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	250 by 2025 (50 per year)	Address only the poles in need of immediate replacement, as identified in the annual pole inspection report.
Additional Feedback (Optional)		

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Making Choices (2 of 7)

Overhead transformer replacement

Transformers are a critical piece of distribution equipment that reduce voltage from the higher levels that are more efficient to move electricity long distances to lower levels that are safer to connect to homes and businesses. They are typically either located on the ground, in underground vaults, or attached to distribution poles

A recent asset health condition assessment shows that **1,251 or approximately 21%** of the overhead transformers in NPEI's distribution system are in poor or very poor condition.

Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances.

However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses.

NPEI is proposing a new program to proactively replace **250 of the 677 or 37%** of the overhead transformers identified as very poor condition before they fail over the course of the next five years.

As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Q10. Which of the following options do you prefer?

Option	Transformers Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	375 by 2025 (75 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	250 by 2025 (50 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	125 by 2025 (25 per year)	Address only the worst of the polemount transformers identified as very poor in the Asset Condition Assessment report.

Additional Feedback (Optional)

Making Choices (3 of 7)

Converting Outdated Underground Kiosk Transformers

NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program has been pushed off, and today, there remains 75 transformers in need of replacement.

NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.

Q11. Which of the following options do you prefer?

Option	Transformers Installed	Expected Outcome
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	55 by 2025 (11 per year)	Work towards eliminating all old installations over the next 7 years.
Reduced Pace ***Decrease*** *of $0.02 per month annually ($0.24 less per year)*	25 by 2025 (5 per year)	Work towards eliminating all old installations over the next 15 years.
Slower Pace ***Decrease*** *of $0.03 per month annually ($0.36 less per year)*	10 by 2025 (2 per year)	Work towards eliminating all old installations over the next 35 years.
Additional Feedback (Optional)		

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Making Choices (4 of 7)

Underground cable replacement

Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years.

Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses.

Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.

Q12. Which of the following options do you prefer?

Option	Km of cable installed	Expected Outcome
Further Accelerated Pace ***Additional*** *$0.13 per month annually ($1.56 more per year)*	24 km by 2025 (4.8 km per year)	Proactively replace more of the cables identified as past end of life in the Asset Condition Assessment Report.
Accelerated Pace ***Additional*** *$0.06 per month annually ($0.72 more per year)*	12 km by 2025 (2.4 km per year)	Proactively replace some of the cables identified as past end of life in the Asset Condition Assessment Report.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	2 km by 2025 (0.4 km per year)	Replace cables past end of life as other work is being completed on associated switchgear or riser poles.

Additional Feedback (Optional)

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Making Choices (5 of 7)

Subdivision underground rehabilitation

71 of the subdivisions in NPEI's service territory were constructed with **direct buried cable** which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier.

While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life.

In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs.

In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed.

Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time.

Between 2021 and 2025, NPEI is proposing a new program that will proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.

Q13. Which of the following options do you prefer?

Option	Km of vault installed	Expected Outcome
Accelerated Pace ***<u>Additional</u>*** *$0.02 per month annually ($0.24 more per year)*	30 km by 2025 (6 km per year)	Install 6 km of ducts or approximately four subdivisions per year.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	15 km by 2025 (3 km per year)	Install 3 km of ducts or approximately two subdivisions per year.
Slower Pace ***<u>Decrease</u>*** *of $0.01 per month annually ($0.12 less per year)*	7.5 km by 2025 (1.5 km per year)	Install 1.5 km of ducts or approximately one subdivision per year.
Additional Feedback (Optional)		

Making Choices (6 of 7)

Overhead rebuilds

Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system.

A recent asset health condition assessment identified a total of **60 areas** within NPEI's service territory that require complete overhead rebuilds**.** Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section.

This program is intended to contribute to the "betterment" of the overhead system by;

- Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and;
- Improving system aesthetics with new and taller poles.

On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's current approach would rebuild **40 out of 60 areas** in the 2021 to 2025 period.

NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.

Q14. Which of the following options do you prefer?

Option	Overhead rebuilds	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	61 km by 2025 (12.2 km per year)	Rebuild 12.2 km per year or approximately 10 projects per year
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	48.5 km by 2025 (9.7 km per year)	Rebuild areas with assets that have been identified as very poor in Asset Condition Assessment. Rebuild 9.7 km per year or approximately 8 projects per year
Slower Pace ***Decrease*** *of $0.03 per month annually ($0.36 less per year)*	36 km by 2025 (7.2 km per year)	Rebuild 7.2 km per year or approximately 6 projects per year
Additional Feedback (Optional)		

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Making Choices (7 of 7)

Grid modernization

New technology has changed the way that NPEI can manage and monitor the distribution system.

Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory.

This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event.

Q15. Which of the following options do you prefer?

Option	Devices installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	20 devices (4 per year)	NPEI to double installation rate to four devices per year.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	10 Devices (2 per year)	Remain at current installation pace of two devices per year. Install new devices to expand NPEI's Smart Grid network. These devices provide better monitoring capability on the system, which leads to improved restoration times during outages.
Slower Pace ***Decrease*** *of $0.005 per month annually ($0.06 less per year)*	5 Devices (1 per year)	NPEI to cut rate of installation in half to one device per year.
Additional Feedback (Optional)		

Impact of Choices

Investment Alternative Summary

Throughout this workbook, you have been asked about **seven key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page you will find the total bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential rate impact will be re-calculated. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Overhead pole replacement

- ☐ **Accelerated Pace**: Additional $0.03 per month annually ($0.36 more per year annually)
- ☐ **Included in Draft Plan**: Within proposed average 2.5% increase over 5-years
- ☐ **Slower Pace**: Decrease of $0.01 per month annually ($0.12 less per year)

Note: these areas will be uniquely populated for each individual customer. The bill impacts of their individual responses will be summed and displayed below.

The total impact of your choices would result in:

+/- $X.XX per month annually (+/- $X.XX per year)

This is in addition to the estimated 2.5% annual increase if Niagara Peninsula Energy continues with its current draft plan.

Impact of Choices

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Again, it is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $2.53 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by $4.29.
- As a result, the distribution charges on the typical residential customer's monthly bill would increase from $33.51 in 2020 to $37.80 by 2025.

Estimated Typical Residential Annual Increase in Monthly Bill (5 year forecast)

	Year	Average Residential Bill	Distribution Portion of Bill	Incremental Rate Change	% Change * (on distribution portion of bill)
Current Rate	2019	$113.32	$33.11		
Budgeted Rate	2020	$115.03	$33.51	$0.40	1.21%
Forecast for next rate period	2021	$116.33	$36.04	$2.53	7.55%
	2022	$118.08	$36.47	$0.43	1.20%
	2023	$119.85	$36.91	$0.44	1.20%
	2024	$121.65	$37.35	$0.44	1.20%
	2025	$123.47	$37.80	$0.45	1.20%
				$4.29	

*** These estimates are preliminary, and are subject to your feedback as the business plan is finalized .**

Q16. Considering what you know about Niagara Peninsula Energy's draft plan – which would see the typical residential customer's distribution portion of their bill increase by $4.29 over the 5-year period – which of the following best represents your point of view?

- ☐ NPEI should improve service, as discussed on the previous pages, even if that means an increase that exceeds $4.29 over the 5-year period
- ☐ NPEI should maintain a $4.29 increase to deliver a program that focuses on the priorities of its draft plan over the 5-year period.
- ☐ NPEI should keep increases below $4.29, even if that could mean reductions in service over the 5-year period.
- ☐ Other [Please specify]
- ☐ Don't know

Q17. Thinking about your answer to the previous question, why do you feel that NPEI should take that approach over the 2021-2025 period? (Optional) [OPEN]

Q18. Do you have any final comments regarding NPEI or the customer engagement that you just completed? (Optional) [OPEN]

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About you

More about you

The following questions are for statistical purposes only. This information is used to segment and group similar people together when the survey results are analysed.

Q19. To the best of your knowledge, does your home receive electrical service via overhead wires, underground cables?

- Overhead wires
- Underground cables
- Don't know

Q19b. Have you experienced any power outages at your home or at your business in the past 12 months which lasted longer than one minute?

- No outages
- 1 outage
- 2 outages
- 3 or more outages
- Don't know

To what extent do you agree or disagree with the following statements?

Q20. The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

- Strongly agree
- Somewhat agree
- Somewhat disagree
- Strongly disagree
- Don't know/No opinion

Q21. Customers are well served by the electricity system in Ontario.

- Strongly agree
- Somewhat agree
- Somewhat disagree
- Strongly disagree
- Don't know/No opinion

About you

More about you

Q22. Which gender identity do you most closely identify with?

- o Male
- o Female
- o Not listed (Please specify)
- o Prefer not to say

Q23. What age category do you fall into?

- o Under 18
- o 18-24
- o 25-34
- o 35-44
- o 45-54
- o 55-64
- o 65-74
- o 75 or older
- o Prefer not to say

Q24. Including yourself, how many people live in your household?

- o Single person household
- o 2 people
- o 3 people
- o 4 people
- o 5 of more people
- o Prefer not to say

Q25. Which of the following categories best describes the total annual income, after taxes, of all the members of your household?

- o Less than $28,000
- o $28,000 to less than $39,000
- o $39,000 to less than $48,000
- o $48,000 to less than $52,000
- o $52,000 or more
- o Prefer not to say

Final Thoughts

Feedback on Niagara Peninsula Energy's Consultation

Niagara Peninsula Energy values your feedback. This is the first time the utility has conducted a review about its upcoming plans in this type of format.

Q26. Overall, did you have a favourable or unfavourable impression of the consultation you just completed?

o Very favourable
o Somewhat favourable
o Somewhat unfavourable
o Very unfavourable
o Don't know

Q27. In this consultation, do you feel that NPEI provided too much information, not enough, or just the right amount?

o Too little information
o Just the right amount of information
o Too much information

Q28. Was there any content missing that you would have liked to have seen included in this consultation?

o None

Q29. Is there anything that you would still like answered?

o None

Appendix F: Asset Condition Assessment (ACA) Report

NIAGARA PENINSULA ENERGY INC.
DISTRIBUTION ASSET CONDITION REPORT - 2018

March 4, 2020

Kinectrics Inc.
800 Kipling Avenue
Toronto, ON
M8Z 6C4 Canada
www.kinectrics.com

DISCLAIMER

NIAGARA PENINSULA ENERGY INC.
DISTRIBUTION ASSET CONDITION REPORT - 2018

Kinectrics Report: K-814158-RA-0001-R1

March 4, 2020

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Dated: 2020-03-04

To: Niagara Peninsula Energy Inc.
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Revision History

Revision Number	Date	Comments	Approved
R0	July 8, 2019	Draft	
R0	November 27, 2019	Revised	
R1	March 4, 2020	Final	

EXECUTIVE SUMMARY

In 2011 Niagara Peninsula Energy Inc. (NPEI) determined a need to perform a condition assessment of its key distribution assets. NPEI selected and engaged Kinectrics Inc. (Kinectrics) to perform the Asset Condition Assessment (ACA). A similar study was re-conducted in 2014. In 2018, Kinectrics was tasked with performing a subsequent assessment.

The asset groups included in the 2018 ACA are as follows: power transformers, pad-mounted transformers (large), pad-mounted transformers (small), pole-mounted transformers, poles (NPEI-owned), poles (Not NPEI-owned), pad-mounted switchgear, UG cables and OH lines. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan was developed.

It was found that pole-mounted transformers had the highest percentages of units in poor to very poor condition. In terms units flagged for action, it was found that the most significant quantities flagged for action in the near future belong to pole-mounted transformers and wood poles.

An audit assessing the ACA changes between 2014 and 2018 was conducted. The following aspects were compared: Health Index formula, population and sample size, and health index distribution. Following is a summary of the findings:

- Between 2014 and 2018, the Health Index formulas for many asset groups were refined to include new data, age limiter curves, and/or refined condition criteria.
- The sample sizes for wood poles, large pad-mounted transformers, and UG cables improved.
- There was a significant improvement in the overall health of pad-mounted switchgear. This is likely a result of new unit installations as well as the effective maintenance work during 2014-2018.
- There was a significant decrease in the overall health of pole-mounted transformers and NPEI owned wood poles. This is likely to be the result of incorporation of loading data and age limiter curve for pole-mounted transformers, and incorporation of age limiter curve and more age data for NPEI wood poles.
- Pad-mounted switchgear had a substantial increase in population. This needs to be verified by NPEI.

The results presented in this study are based solely on asset condition as determined by available data. Note that there are numerous other considerations that may influence NPEI's planning process. Among these are obsolescence, system growth, corporate priorities, technological advancements, etc.

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I INTRODUCTION

Niagara Peninsula Energy Inc. (NPEI) is a local distribution company (LDC) that serves over 51,000 customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham and Township of West Lincoln.

NPEI is jointly owned by Niagara Falls Holding Corporation and Peninsula West Power Inc. Niagara Falls Holding Corp. is wholly owned by the City of Niagara Falls. Peninsula West Power Inc., which is also a Holding Company, is jointly owned by the Town of Lincoln, the Town of Pelham and the Township of West Lincoln. NPEI is governed by an eight member Board of Directors and is licensed by the Ontario Energy Board (OEB).

Kinectrics Inc. (Kinectrics) is an independent consulting engineering company with the advantage of 100 years of expertise gained as part of one of North America's largest integrated electric power companies. Kinectrics has a depth of experience in the area of transmission and distribution systems and has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America.

In 2011 Kinectrics performed an Asset Condition Assessment (ACA) on NPEI's key distribution assets. Kinectrics was again tasked with performing an ACA for NPEI in 2014 and 2018 respectively. This report presents the results of the 2018 ACA, as well as the audit on changes from 2014 to 2018.

This Asset Condition Assessment Report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

I.1 Objective and Scope of Work

The scope of work includes an assessment of the following asset classes:

- Power Transformers
- Large Pad-mounted Transformers
- Pole-top Transformers
- Wood Poles
- Standard Pad-mounted Transformers
- Pad-mounted Switchgear
- Underground Cables
  - Main Feeder
  - Distribution

For each asset category, the ACA included the following tasks:

- Gathering relevant condition data
- Developing a Health Index Formula
- Calculating the Health Index for each asset
- Determining the Health Index distribution
- Developing a 20-year condition-based Flagged for Action Plan
- Identifying and prioritizing the data gaps for each group

For each asset category, the Health Index formulation, Health Index distribution, condition-based Flagged for Action Plan, and a data assessment in terms of the data availability indicator (DAI) and data gap analysis are given.

I.2 Data Source

The data used in this study was provided to Kinectrics by NPEI are summarized as follows:

Asset Category	File Name
Power Transformers	2.1.1 Power_Transformers_Nameplate and Oil Analysis
	2.1.2 Substation_Transformer_Maintenance_Data
	2.1.3 - MS_Inspections_Consolidated_Peak & Visual
	2.1.4 - Kalar TS Inspections Consolidated Peak & Visual
Pad Mounted Transformers (≥ 1 MVA)	2.2.1 Nameplate 201904
	2.2.2 Transformer Oil Analysis
	2.2.3 Visual Inspections 201904
	2.2.4 Loading 201904
Pad Mounted Transformers (< 1 MVA)	2.3.1 Nameplate 201904
	2.3.2 Visual Inspections 201904
	2.3.3 UG Transformer Loading 201904xls
Pole Mounted Transformers	2.4.1 Nameplate 201904
	2.4.2 Loading 201904
	2.4.3 Visual Inspection 201904
	2.4.4 Historical Removed Records 201904
Poles (NPEI Owned)	2.5.2 and 2.5.3 Visual Inspection 201904
	2.5.5 Asset Category Wood Pole 201904
	2.5.6 Asset Category Concrete Polel 201904
	2.5.7 Asset Category Steel Pole 201904
Poles (non NPEI owned)	2.6.2 and 2.6.3 Visual Inspection
	2.6.5 Asset Category Wood Pole Foreign
	2.6.6 Asset Category Concrete Pole Foreign
	2.6.7 Asset Category Steel Pole Foreign
Pad Mounted Switchgear	2.7.1 Nameplate
	2.7.2 Visual Inspections
Underground Cables	2.8.1 Nameplate AGE - INSTALL DATE
Overhead Lines	2.9.1 Nameplate AGE - INSTALL DATE

I.3 Deliverables

The deliverable in this study is a Report that includes the following information:

- For each asset category the following are included (Appendix A: Results and Findings for Each Asset Category):
    - Health Index formulation
    - Age distribution
    - Health Index distribution
    - Condition-based Flagged For Action Plan
    - Assessment of data availability by means of a Data Availability Indicator (DAI) and a Data Gap analysis
- An audit describing the key changes between 2014 and 2018

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II ASSET CONDITION ASSESSMENT METHODOLOGY

The Asset Condition Assessment (ACA) Methodology involves the process of determining asset Health Index, as well as developing a condition-based Flagged for Action Plan for each asset group. The methods used are described in the subsequent sections.

II.1 Health Index

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or intervention in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a power transformer parameter called "Oil Quality" may be a composite of parameters such as "moisture", "acid", "interfacial tension", "dielectric strength" and "color".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of the condition parameter scores and weightings, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DR$$

Equation 1

where

$$CPS = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{n=1}^{\forall n} \beta_n (CPF_{n.\max} \times WCPF_n)} \times CPS_{\max}$$

Equation 2

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient for condition parameter
CPF	Sub-Condition Parameter Score
WCPF	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. For this project, a condition criteria scoring system of 0 through 4 is used. A score of 0 represents the worst score while 4 represents the best score. I.e. $CPF_{max} = 4$.

De-Rating multipliers are applied to the calculated HI. These may be used to represent the impact of non-condition issues such as design or operating environment.

II.1.1 Health Index Results

As stated previously, an asset's Health Index is given as a percentage, with 100% representing "as new" condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index ≤ 30%
Poor	30 < Health Index ≤ 50%
Fair	50 < Health Index ≤70%
Good	70 < Health Index ≤85%
Very Good	Health Index > 85%

Note that for critical asset groups, such as Power Transformers, the Health Index of each individual unit is given.

II.2 **Condition Based Flagged for Action Plan**

The condition based Flagged for Action Plan outlines the number of units that are expected to require attention in the next 20 years. The numbers of units are estimated using either a *proactive* or *reactive* approach. In the proactive approach, units are considered for action prior to failure, whereas the reactive approach is based on expected failures per year.

Both approaches consider asset failure rate and probability of failure. The failure rate is estimated using the method described in the subsequent section.

II.2.1 Failure Rate and Probability of Failure

Where removal rate data is not available, a frequency of removal that grows exponentially with age provides a good model.

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' experience in removal rate studies of multiple power system asset groups, Kinectrics has selected the Weibull equation to model the removal curves. The Weibull function has no specific characteristic shape and, as such, can model the exponentially increasing removal rate using appropriate parameters.

The Weibull removal density function is defined as:

$$f(t) = \frac{\beta t^{\beta-1}}{\alpha^{\beta}} e^{-(\frac{t}{\alpha})^{\beta}}$$

Equation 3

f = removal rate per unit time
t = time
α, β = constant that control the scale and shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' experience in removal rate studies of multiple power system asset groups, the following variation of the removal rate formula has been adopted:

The corresponding cumulative removal distribution is therefore:

$$Q(t) = 1 - R(t) = 1 - e^{-(\frac{t}{\alpha})^{\beta}}$$

Equation 4

Q(t) = cumulative failure distribution
R(t) = survival function

Finally, the removal rate function (i.e. hazard function) is then:

$$\lambda(t) = \frac{f(t)}{1 - Q(t)} = \frac{\beta t^{\beta-1}}{\alpha^{\beta}}$$

Equation 5

$\lambda(t)$ = hazard function (removals per year)

Different asset groups experience different removal rates and therefore different removal distributions. The parameters α and β are determine the shapes of these curves. For each asset group, the values of these constant parameters were selected to reflect typical useful lives for these assets.

Consider, for example, an asset class where at the ages of 40 and 75 the asset has cumulative probabilities of removal of 20% and 95% respectively. It follows that when using Equation 5, α and β are calculated as 57.503 and 4.132 respectively. The removal rate and probability of removal graphs for these parameters are as follows:

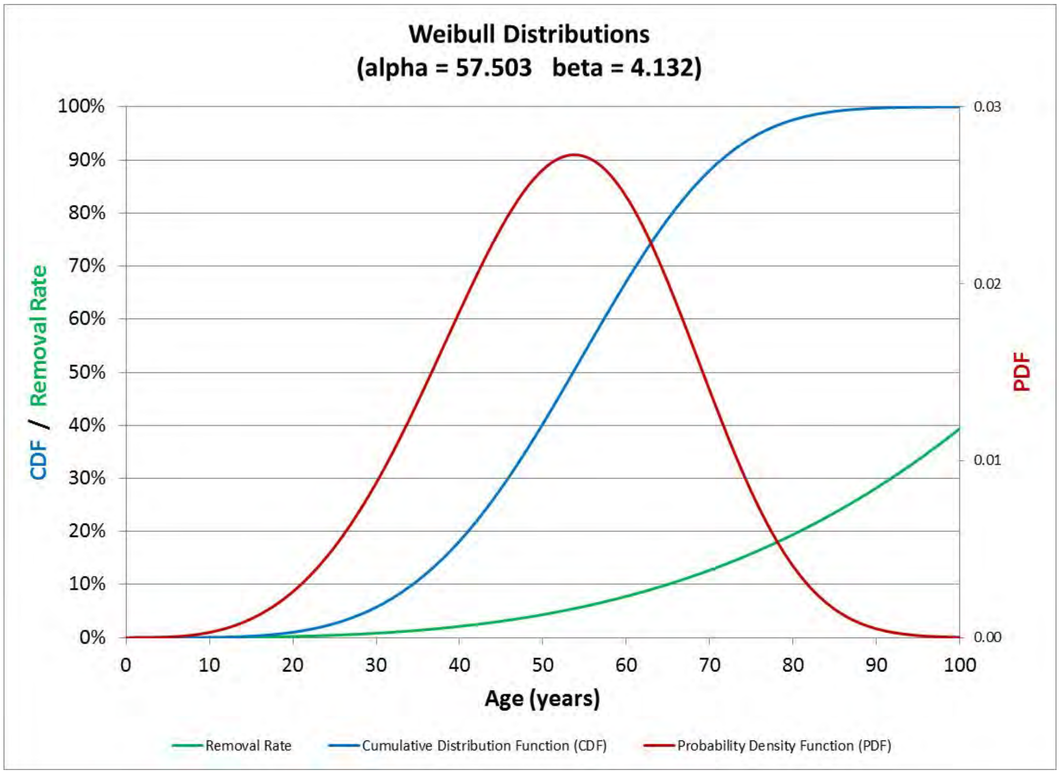

Figure 1 Removal rate vs. Age

II.2.2 Projected Flagged for Action Plan Using a Reactive Approach

Because the consequences of failure are relatively small, many types of distribution assets are reactively replaced.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's failure rates. The number of failures per year is given by Equation 4 as mentioned before

An example of such a Flagged for Action Plan is as follows: Consider an asset distribution of 100 - 5 year old units, 20 – 10 year old units, and 50 - 20 year old units. Assume that the failure rates for 5, 10, and 20 year old units for this asset class are f_5 = 0.02, f_{10} = 0.05, f_{20} = 0.1 failures / year respectively. In the current year, the total number of replacements is 100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8.

In the following year, the expected asset distribution is, as a result, as follows: 8 – 1 year old units, 98 – 6 year old units, 19 – 11 year old units, and 45 - 21 year old units. The number of replacements in year 2 is therefore 8(f_1) + 19(f_6) + 45(f_{11})+ 45(f_{21}).

Note that in this study the "age" used is in fact "effective age", or condition-based age if available, as opposed to the chronological age of the asset.

II.2.3 Projected Flagged for Action Plan Using a Proactive Approach

For certain asset classes, the consequence of an asset failure is significant, and, as such, these assets are proactively addressed prior to failure. The proactive replacement methodology involves relating an asset's Health Index to its probability of failure by considering the stresses to which it is exposed.

Relating Health Index and Probability of Failure

If there are no dominant sources, it can be assumed that the stress to which an asset is exposed is not constant and will have a somewhat normal frequency distribution. This is illustrated by the probability density curve of stress below. The vertical lines in the figure represent condition or strength (Health Index) of an asset.

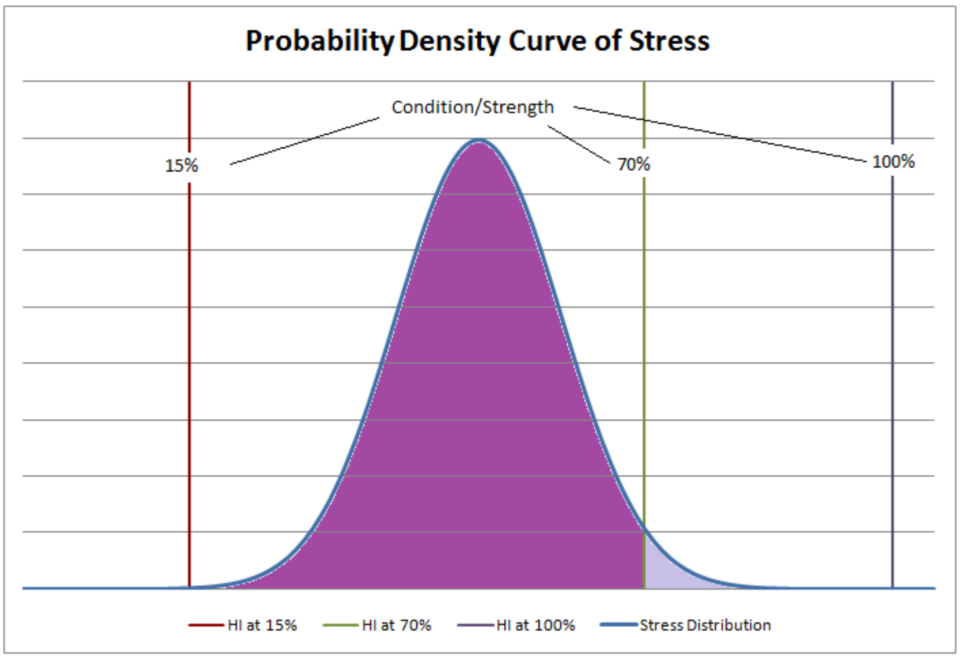

Figure 2 Stress Curve

An asset is in as-new condition (100% strength) should be able to withstand most levels of stress. As the condition of the asset deteriorates, it may be less able to withstand higher levels of stress. Consider, for example, the green vertical line that represents 70% condition/strength. The asset should be able to withstand magnitudes of stress to left of the green line. If, however, the stress is of a magnitude to the right of the green line, the asset will fail.

To create a relationship between the Health Index and probability of failure, assume two "points" on the stress curve that correspond to two different Health Index values. In this example, assume that an asset that has a condition/strength (Health Index) of 100% can withstand all magnitudes of stress to the left of the purple line. It then follows that probability that an asset in 100% condition will fail is the probability that the magnitude of stress is at levels to the right of the purple line. This corresponds to the area under the stress density curve to the right of the purple line. Similarly, if it assumed that an asset with a condition of 15% will fail if subjected to stress at magnitudes to the right of the red line, the probability of failure at 15% condition is the area under the stress density curve to the right of the red line.

The probability of failure at a particular Health Index is found from plotting the Health Index on X-axis and the area under the probability density curve to the right of the Health Index line on Y-axis, as shown on the graph of the figure below.

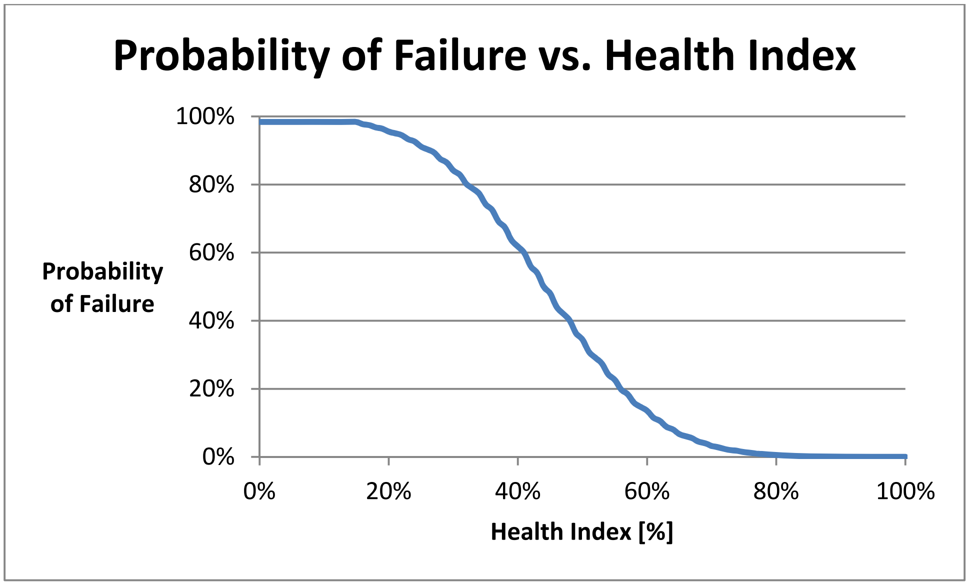

Figure 3 Probability of Failure vs. Health Index

Condition-Based Flagged for Action Plan

To develop a Flagged for Action Plan, the risk of failure of each unit must be quantified. Risk is the product of a unit's probability of failure and its consequence of failure. The probability of failure is determined by an asset's Health Index. In this study, the metric used to measure consequence of failure is referred to as *criticality*.

Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values being examples. For Power Transformers, factors that impact criticality may include things like number of customers or location. The higher the criticality value assigned to a unit, the higher is it's consequence of failure.

In this study, it is assumed that the unit that has the highest relative consequence of failure has a criticality of 1.25. When its risk value, the product of its probability of failure and criticality, is greater than or equal to 1, the unit is flagged for action.

III DATA ASSESSMENT

The condition data used in this study were obtained from NPEI and included the following:

- Asset Properties (e.g. age, location information)
- Test Results (e.g. Oil Quality, DGA)
- Inspection Records

There are two components that assess the availability and quality of data used in this study: Data Gap and Data Availability Indicator (DAI).

III.1 Data Gap

The Health Index formulations developed and used in this study are based solely on NPEI's available data. There are additional parameters or tests that NPEI may not collect but nonetheless are important indicators of the deterioration and degradation of assets. The set of unavailable data are referred to as data gaps. I.e. A data gap is the case where none of the units in an asset group has data for a particular item. The situation where data is provided for only a sub-set of the population is *not* considered as a data gap.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation.

Priority	Description	Symbol
High	Critical data; most useful as an indicator of asset degradation	☆☆☆
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	☆☆
Low	Helpful data; least indicative of asset deterioration	☆

It is generally recommended that data collection be initiated for the most critical items because such information will result in higher quality Health Index formulations.

The more critical and important data included in the Health Index formula of a certain asset group, and the higher the Data Availability Indicator of a particular unit in that group, the higher the confidence in the Health Index calculated for the particular unit.

If an asset group has significant data gaps and lacks good quality condition, there is less confidence that the Health Index score of a particular unit accurately reflects its condition, regardless of the value of its DAI.

To facilitate the incorporation of data gap items into improved Health Index formulas for future assessments, the data gaps items are presented in this report as sub-condition parameters. For each item, the parent condition parameter is identified. Also given are the object or component addressed by the parameter, a description of what to assess for each component or object, and the possible source of data.

The following is an example for "Tank Corrosion" on a Pad-Mounted Transformer:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	☆☆	Oil Tank	Tank surface rust or deterioration due to environmental factors	Visual Inspection

III.2 Data Availability Indicator (DAI)

The Data Availability Indicator (DAI) is a measure of the amount of condition parameter data that an asset has, as measured against the condition parameters included in the Health Index formula. It is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the "best" overall weighted, total condition parameters score. The formula is given by:

$$DAI = \frac{\sum_{m=1}^{\forall m} (DAI_{CP\,m} \times WCP_m)}{\sum_{m=1}^{\forall m} (WCP_m)}$$

Equation 6

where

$$DAI_{CPm} = \frac{\sum_{n=1}^{\forall n} (\beta_n \times WCF_n)}{\sum_{n=1}^{\forall n} (WCF_n)}$$

Equation 7

DAI	Overall Data Availability Indicator for an asset with m Condition Parameters
DAI_{CPm}	Data Availability Indicator for Condition Parameter
WCP_m	Weight of Condition Parameter m
β_n	Data Availability Coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WCPF_n$	Weight of Condition Parameter Factor n

For example, consider an asset with the following condition parameters and sub-condition parameters:

Condition Parameter		Condition Parameter Weight (WCP)	Sub-Condition Parameter		Sub-Condition Parameter Weight (WCF)	Data Available? (β = 1 if available; 0 if not)
m	Name		n	Name		
1	A	1	1	A_1	1	1
2	B	2	1	B_1	2	1
			2	B_2	4	1
			3	B_3	5	0
3	C	3	1	C_1	1	0

The Data Availability Indicator is calculated as follows:

$DAI_{CP1} = (1*1) / (1) = 1$
$DAI_{CP2} = (1*2 + 1*4 + 0*5) / (2 + 4 + 5) = 0.545$
$DAI_{CP3} = (0*1) / (1) = 0$

$$DAI = (DAI_{CP1}*WCP_1 + DAI_{CP2}*WCP_2 + DAI_{CP3}*WCP_3) / (WCP_1 + WCP_2 + WCP_3)$$
$$= (1*1 + 0.545*2 + 0*3) / (1 + 2 + 3)$$
$$= 35\%$$

An asset with all condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score.

It is important to note that while an asset may have a high DAI, having large data gaps will still result in a less reliable Health Index. For example, if the Health Index is based only on age and the entire asset population has age data, the average DAI for that asset category will be 100%. As age is not necessarily equal to condition, there may still be low confidence in the Health Index results for this asset category.

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IV RESULTS

IV.1 Health Index Results

A summary of the Health Index evaluation results is shown in Table 1. For each asset category the population, sample size (number of assets with sufficient data for Health Indexing), and age are given. The average Health Index and distribution are also shown. A summary of the Health Index distribution for all asset categories are also graphically shown in Figure 4. Note that the Health Index distribution percentages are based on the asset group's sample size.

It can be seen from the results pole mounted transformers have the highest percentages of units in poor and very poor condition, while steel poles (both NPEI owned and non NPEI owned) and overhead lines have all their units in good and very good condition.

IV.2 Condition Based Flagged for Action Plan

Table 2 shows year 1 of the Flagged for Action Plan as well as the asset action strategy for each asset group. Note that in deriving the plans, it is assumed that sample size-based Health Index distribution of a given asset category is applicable to the entire asset population (i.e. the Health Index distribution is extrapolated to the asset population and the Flagged for Action plan is based on the whole asset population).

Table 3 shows the 20 year Flagged for Action Plan. The Flagged for Action Plan is based on the number of units expected to require attention in a given year. As it may not always be feasible to address assets as per this plan, a "levelized" plan is adopted. In this study, levelized Flagged for Action Plan is applied for pole mounted transformers, wood poles (both NPEI owned and non NPEI owned) and underground cables.

It is important to note that the Flagged for Action Plan suggested in this study is based solely on asset Health Index, derived from available condition data and information. It uses a probabilistic, non-deterministic, approach and as such can only show expected failures or probable number of units for flagged for action. While the Condition-Based Flagged for Action Plan can be used as a guide or input into NPEI's asset management activities, it is not expected that it be followed directly or as the final deciding factor in capital decisions. There are numerous other factors and considerations, such as obsolescence, system growth, corporate priorities, technological advancements, etc., that will influence NPEI's asset management decisions.

NPEI's most significant asset groups, in terms of number of units flagged for action in the near future, were pole-top transformers and wood poles. In year 1 it is estimated that 377 pole-top transformers and 1054 wood poles (both NPEI owned and non NPEI owned) respectively will require attention. The most significant asset groups in terms of percentage in the near future are power transformers and pole mounted transformers, both having over 5% units flagged for action in year 1.

Table 1 Health Index Results Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age	Average DAI	Age Availability
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)			
Power Transformers		20	20	77%	1	0	3	8	8	27	61%	100%
Pad-Mount Transformers - Large		74	74	95%	0	0	3	6	65	15	43%	100%
Pad-Mount Transformers - Small		3391	3369	96%	0	14	57	68	3230	17	57%	99%
Pole-Mount Transformers		6077	6051	74%	677	574	831	866	3103	25	96%	87%
Poles - NPEI Owned	Wood	23830	23733	81%	1042	1944	1807	3523	15417	33	88%	98%
	Concrete	621	618	91%	2	13	4	85	514	29	88%	98%
	Steel	371	370	95%	0	0	0	1	369	20	92%	100%
Poles - Non NPEI Owned	Wood	7053	6841	91%	98	148	80	557	5958	13	85%	25%
	Concrete	5719	5690	95%	2	10	24	143	5511	8	79%	35%
	Steel	680	646	96%	0	0	0	13	633	7	63%	52%
Pad-Mount Switchgear		170	61	92%	0	1	1	3	56		35%	0%
Underground Cables *		570.9	433.5	95%	3.8	10.8	9.3	18.5	391.0	13	0%	76%
Overhead Lines *		1451.7	558.0	100%	0.0	0.0	0.0	0.1	557.9	3	0%	38%

* by length (km)

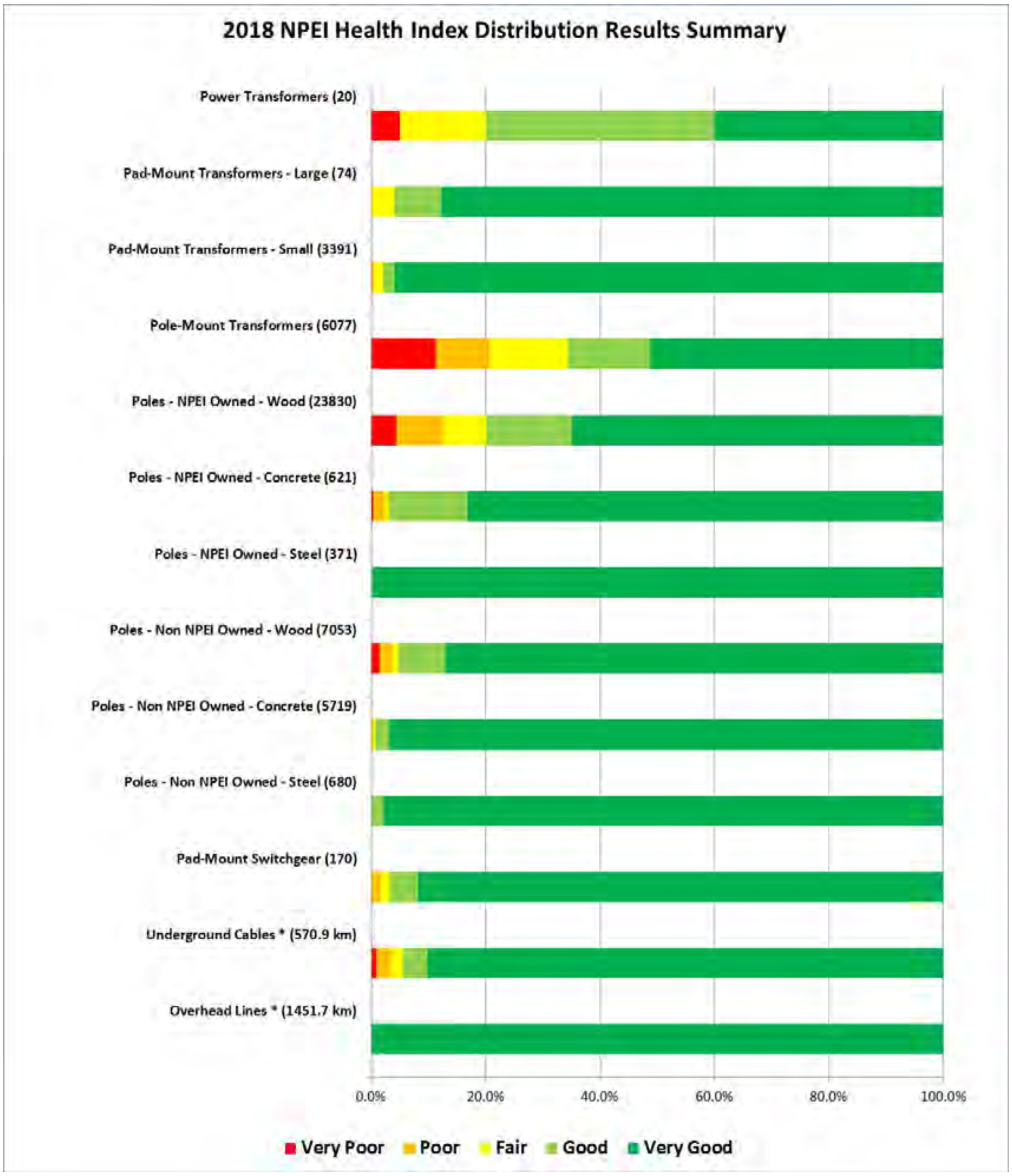

Figure 4 Health Index Results Summary

Table 2 Year 1 Condition Based Flagged for Action

Asset Category		1st Year		10 Year Replacement		Replacement Strategy
		Quantity	Percentage	Quantity	Percentage	
Power Transformers		1	5.0%	4	20.0%	Proactive
Pad-Mount Transformers - Large		0	0.0%	0	0.0%	Proactive
Pad-Mount Transformers - Small		13	0.4%	168	5.0%	Proactive
Pole-Mount Transformers		377	6.2%	2627	43.4%	Proactive
Poles - NPEI Owned	Wood	968	4.1%	6465	27.2%	Proactive
	Concrete	6	1.0%	35	5.6%	Reactive
	Steel	0	0.0%	0	0.0%	Reactive
Poles - Non NPEI Owned	Wood	86	1.2%	612	8.7%	Reactive
	Concrete	10	0.2%	70	1.2%	Reactive
	Steel	0	0.0%	0	0.0%	Proactive/Reactive
Pad-Mount Switchgear		3.0	1.8%	30.0	17.6%	Proactive/Reactive
Underground Cables *		15.0	2.6%	93.0	16.3%	Reactive
Overhead Lines *		0.0	0.0%	1.2	0.1%	Reactive

* by length (km)

Table 3 Twenty Year Condition Based Flagged for Action Plan

Asset Category		Flagged for Action Plan by Year																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Power Transformers		1	0	0	0	0	0	0	0	1	2	4	3	1	3	2	0	1	0	0	0
Pad-Mount Transformers - Large		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pad-Mount Transformers - Small		13	14	15	16	16	16	18	19	20	21	21	22	23	24	26	26	27	28	30	30
Pole-Mount Transformers		377	290	288	288	288	288	288	288	116	116	116	111	111	111	111	111	111	111	110	110
Poles - NPEI Owned	Wood	968	726	726	726	726	726	726	726	208	207	188	188	188	188	188	188	188	188	188	188
	Concrete	6	5	4	4	3	3	3	2	2	3	3	3	3	3	4	4	4	4	4	4
	Steel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Poles - Non NPEI Owned	Wood	86	66	66	66	66	66	66	66	32	32	32	32	32	32	32	32	32	32	32	32
	Concrete	10	9	8	7	6	6	6	6	6	6	7	7	7	8	8	8	8	8	8	8
	Steel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pad-Mount Switchgear		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Underground Cables *		15.0	15.0	15.0	15.0	12.0	4.0	5.0	4.0	4.0	4.0	5.0	4.0	5.0	5.0	5.0	5.0	6.0	6.0	6.0	5.0
Overhead Lines *		0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.6	0.7	1.0	1.1	1.8	1.9	2.1	2.4	2.9

* by length (km)

IV.3 Data Assessment Results

The types of data available for power transformers include oil quality, dissolved gas analysis, power dissipation factor, furan tests and loading, as well as age and inspections related to bushing, leaks and tank condition.

The types of data available for large pad-mount transformers include oil quality and dissolved gas analysis, loading, as well as age and inspection records. More detailed inspections were not available for this asset group.

The types of data available for small pad-mount transformers include loading, age and inspection records. Information on oil quality or dissolved gas analysis was not available for this asset group.

Age and loading were the only available data for pole-top transformers. Data gaps include information regarding transformer physical condition (e.g. condition of enclosure, leaks, bushing, elbows/inserts, etc.), typically gathered from visual inspections.

NPEI’s pole inspection program provides information on pole age, type and pole strength. Pole accessories (e.g. cross arms, guy wires, grounding, etc.) are also inspected.

Pad-mounted switchgear are subject to inspections every 5 years. Inspection data includes condition of enclosure, base, insulation, grounding, and overall switchgear condition. Infrared and ultrasonic tests are also available for this asset group. Age was however not available for this asset group.

Age was the only available information for underground cables. While this asset group has regular visual inspections and infrared and ultrasonic scans, such data has not yet been incorporated into the Health Index. Additional data gaps include test results (e.g. insulation resistance, AC withstand, partial discharge, dielectric loss, time domain reflectometry) and failure statistics.

Age was the only available information for overhead lines.

V 2014 TO 2018 AUDIT

In 2014 a full Asset Condition Assessment (ACA) for key distribution assets was conducted for NPEI by Kinectrics. Between 2014 and 2018, NPEI took steps to adopt the recommendations prescribed by the 2014 ACA and to improve the quality of its condition data. As described in this report, a subsequent ACA was conducted by Kinectrics for NPEI's assets as of 2018. In addition, Kinectrics assessed the changes with respect to ACA between the 2014 and 2018. This section of the report describes the findings.

Asset Categories

Health Index (HI) formulation and results from 2014 and 2018 were compared for the following Asset Categories and Sub-Categories:

- Power Transformers
- Large Pad-mounted Transformers
- Small Pad-Mounted Transformers
- Pole-Mounted Transformers
- Wood Poles
- Pad-mounted Switchgear
- Underground Cables

Overhead lines, which are included in the 2018 assessment were not assessed in 2014 and are therefore not included in the audit.

Audit Results

For each Asset Category, the following aspects were compared between 2011 and 2014:

1. Health Index Formulation
2. Population and Sample Size
3. Health Index Distribution

V.1 Changes in Health Index Formulation

A global change in 2018 study is that for all the asset groups, age was treated as a limiter factor for overall health index result rather than an individual condition parameter.

The age limiter curves were assumed to follow Weibull distribution rather than Gompertz distribution. The curves were developed based on NPEI historic removal records for small pad-mounted transformers and pole-mounted transformers. The curves for the rest asset groups were based on industry practice.

A major change in health index formula for power transformers was that in 2018 study, the formula was component oriented, with the original oil DGA and oil quality condition parameters being further sub-categorized and reshuffled. More condition parameters were included.

Since 2014, additional condition data has become available for Power Transformers. As such, the 2018 Health Index Formula incorporated Furan compound, loading and more detailed inspection records.

Compared to 2014, 2018 study had loading data available for all types of transformers.

V.2 Changes in Population and Sample Size

Table 4 summarizes the Change in Population and in Sample Size between 2014 and 2018. Graphical representations of the data are given on Figure 5 and Figure 6.

Changes in Population

The population of power transformers increased by 1, or 5%, between 2014 and 2018. In 2018 the following numbers of transformers were included: Armoury A-113 (spare), portable sub, station 17 Virginia St and station 23 Dorchester Rd. Meanwhile, the 2 units at Campden D.S. and Jordan D.S. of Penwest and 1 unit at O'Neil A-148 of Niagara Falls were removed.

The 8 unit, or 12% increase, of large pad-mounted transformers between 2014 and 2018 was a result of data validation and transformer classification.

The population of small pad-mounted transformers increased by 709 units (26%). The population of pad-mounted switchgear, however, increased by 96 units (130%). These were the 2 asset groups with the greatest population change.

The population of pole-top transformers decreased by 9%, whereas the population of wood poles (NPEI owned) decreased by 3%. These were the 2 asset groups with decreased population.

The underground cables increased by 20% for its length.

Changes in Sample Size

Ideally, condition data should be available for every asset within a population. Failing that, the larger the sample size, or subset of assets with sufficient condition information for Health Indexing, the more confidence there is in extrapolating the ACA results over an entire asset population.

The sample sizes for power transformers, small pad-mounted transformers and pole-mounted transformers were close to 100% in 2014 and remained steady in 2018.

In 2014 large pad-mounted transformers had a sample size of 95%. A 5% improvement was seen in 2018 where the sample size rose to 100%.

In 2018 data was available for 100% of wood poles. This represents a 3% increase in sample size since 2014. For underground cables, the sample size improved from 66% in 2014 to 76% in 2018, an increase by 10%.

Meanwhile, the sample size of small pad-mounted transformers slightly decreased by 1% (to 99%) in 2018. Pad-mounted switchgear however had a significant decrease in sample size, from 81% in 2014 to 36% in 2018. This was due to the fact that the new inventory list had substantial increase in its population, while there was little change in available inspection data.

Table 4 Summary Change in Population and Sample Size

Asset	Population				Sample Size		
	Population Count 2014	Population Count 2018	Population Change by Counts	Population Change by %	% Sample Size 2014	% Sample Size 2018	Sample Size Change by %
Power Transformers	19	20	1	5%	100%	100%	0%
Pad-Mount Transformers - Large	66	74	8	12%	95%	100%	5%
Pad-Mount Transformers - Small	2682	3391	709	26%	100%	99%	-1%
Pole-Mount Transformers	6683	6077	-606	-9%	99%	100%	0%
Wood Poles	24546	23830	-716	-3%	96%	100%	3%
Pad-Mount Switchgear	74	170	96	130%	81%	36%	-45%
Underground Cables *	475.0	570.9	95.9	20%	66%	76%	10%

* by length (km)

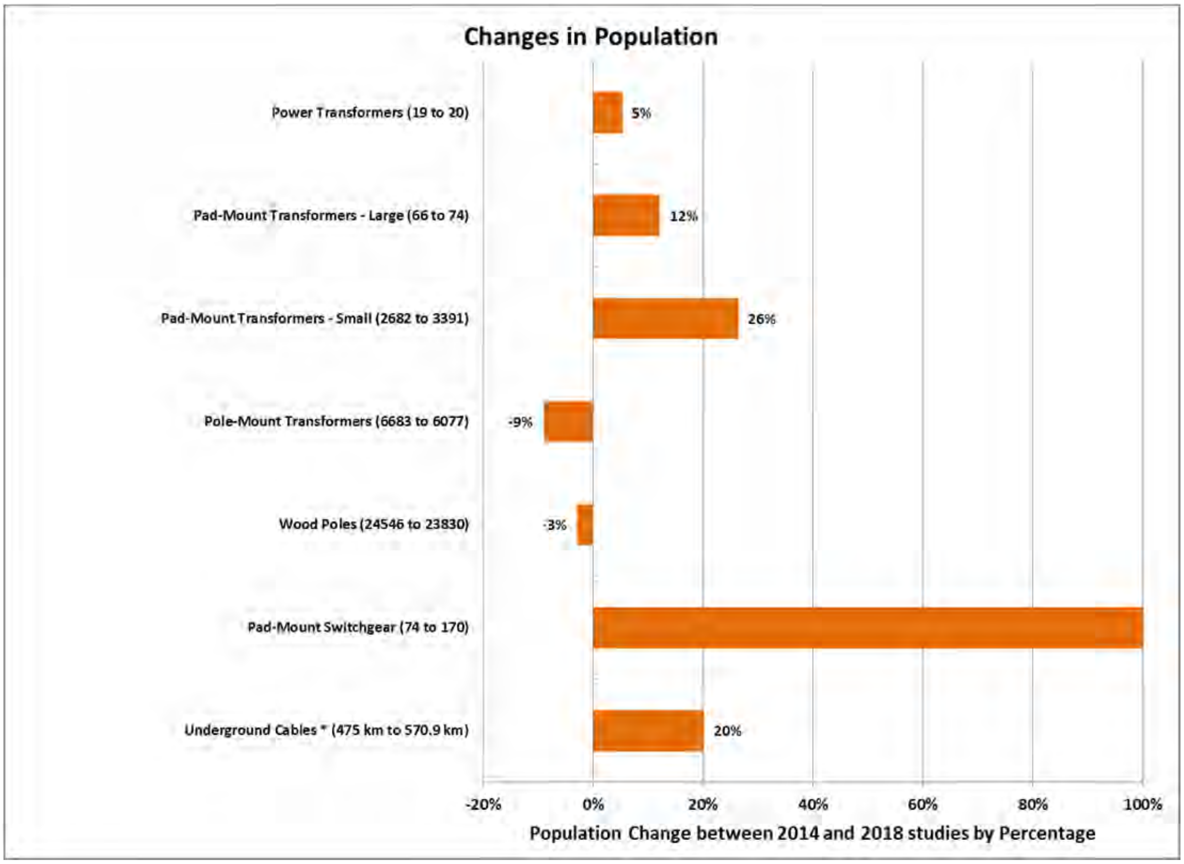

Figure 5 Change in Population

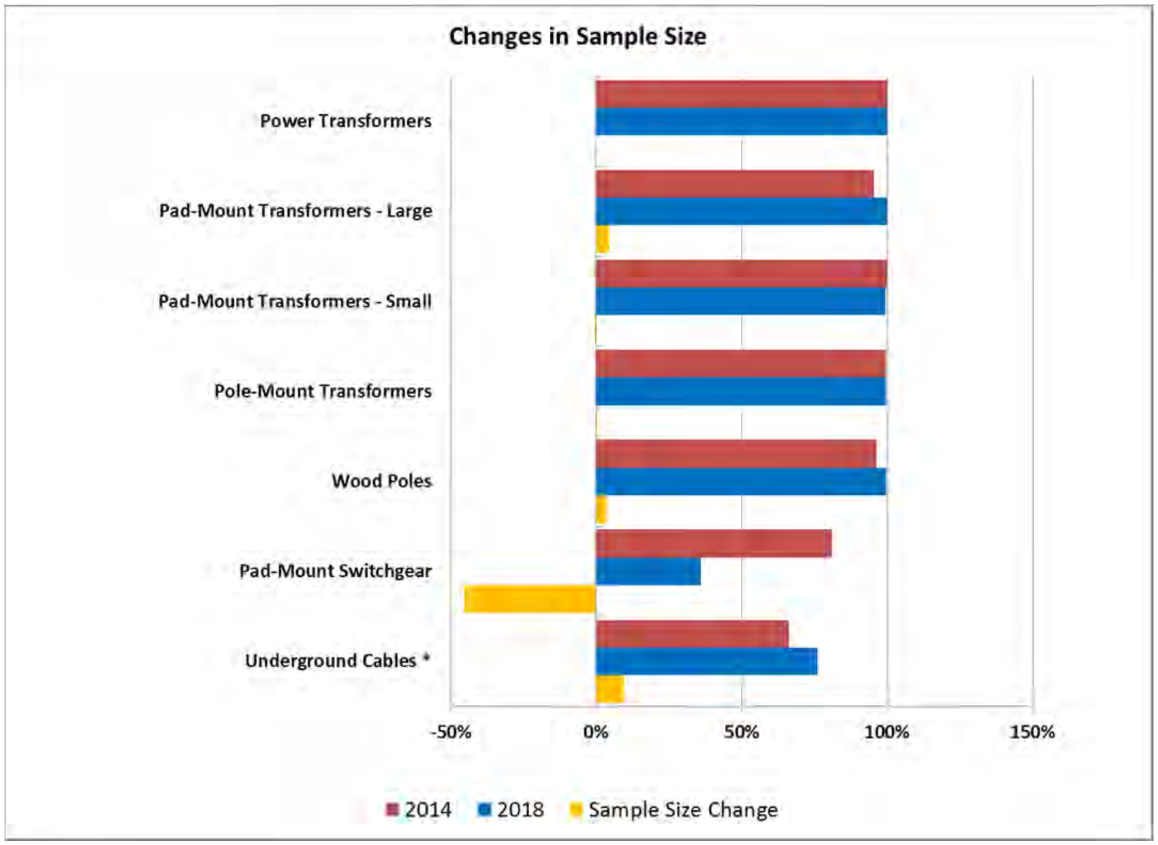

Figure 6 Change in Sample Size

V.3 Changes in Health Index Distribution

The changes in Health Index distribution between 2014 and 2018 are summarized in Table 5 and graphically shown in Figure 7.

The overall trend with respect to Health Index distribution was assessed. Assets that showed an increasing percentage of “good” and/or “very good” or a decrease of “very poor”, “poor”, and/or “fair” were classified as having overall improved health distributions. Conversely, asset classes with a decreasing percentage of “good” and/or “very good” or an increasing percentage of “very poor”, “poor”, and/or “fair” were classified as having an overall decline in health.

Power Transformers: The trend shows a general degradation in overall condition. One unit was in very poor condition due to its ageing. The application of the refined HI formula also had impact on the health index distribution.

Large Pad-mounted Transformers: The trend shows a minor improvement in overall condition. Many assets that were classified as “good” are now classified as “very good”, but this is likely a result of Health Index formula refinement (e.g. new condition parameters incorporated, age limiter factor).

Small Pad-mounted Transformers: Small pad-mounted transformers showed very little change in overall health. This could be the combined effect of normal ageing and the large quantity of new unit installation since 2014.

Pole-mounted Transformers: It appears that there is an overall decrease in condition. This is likely to be the result of Health Index formula refinement (e.g. age limiter factor and incorporation of loading data).

Wood Poles: Wood poles showed decrease in overall health. This change may be due to the normal degradation process and the incorporation of pole age and strength data.

Pad-mounted Switchgear: Pad-mounted switchgear showed a substantial improvement in overall health. As there was no age data, health index was based on counting of inspection findings. This change was a reflection of the inspection results since 2014, implying the improved condition status after maintenance.

Underground Cables: Underground cables showed no change in overall condition. This could be the combined effect of normal ageing and the large quantity of new cable installation since 2014.

Table 5 Summary Change in Health Index Distribution

Asset	Year	Very Poor		Poor		Fair		Good		Very Good		Average Health Index	
		% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	%	Change
Power Transformers	2014	0.0%	5%	5.3%	-5%	0.0%	15%	36.8%	3%	57.9%	-18%	85.7%	-9%
	2018	5.0%		0.0%		15.0%		40.0%		40.0%		76.6%	
Pad-Mount Transformers - Large	2014	0.0%	0%	0.0%	0%	3.2%	1%	12.7%	-5%	84.1%	4%	92.8%	3%
	2018	0.0%		0.0%		4.1%		8.1%		87.8%		95.5%	
Pad-Mount Transformers - Small	2014	0.0%	0%	0.1%	0%	0.6%	1%	2.3%	0%	97.0%	-1%	96.8%	-1%
	2018	0.0%		0.4%		1.7%		2.0%		95.9%		95.6%	
Pole-Mount Transformers	2014	0.5%	11%	2.8%	7%	3.0%	11%	11.4%	3%	82.2%	-31%	92.3%	-18%
	2018	11.2%		9.5%		13.7%		14.3%		51.3%		74.0%	
Wood Poles	2014	0.1%	4%	3.3%	5%	2.2%	5%	6.3%	9%	88.1%	-23%	95.3%	-14%
	2018	4.4%		8.2%		7.6%		14.8%		65.0%		81.4%	
Pad-Mount Switchgear	2014	0.0%	0%	1.7%	0%	51.7%	-50%	5.0%	0%	41.7%	50%	81.1%	11%
	2018	0.0%		1.6%		1.6%		4.9%		91.8%		92.3%	
Underground Cables *	2014	0.3%	1%	2.0%	0%	2.3%	0%	6.1%	-2%	89.1%	1%	94.7%	0%
	2018	0.9%		2.5%		2.1%		4.3%		90.2%		95.0%	

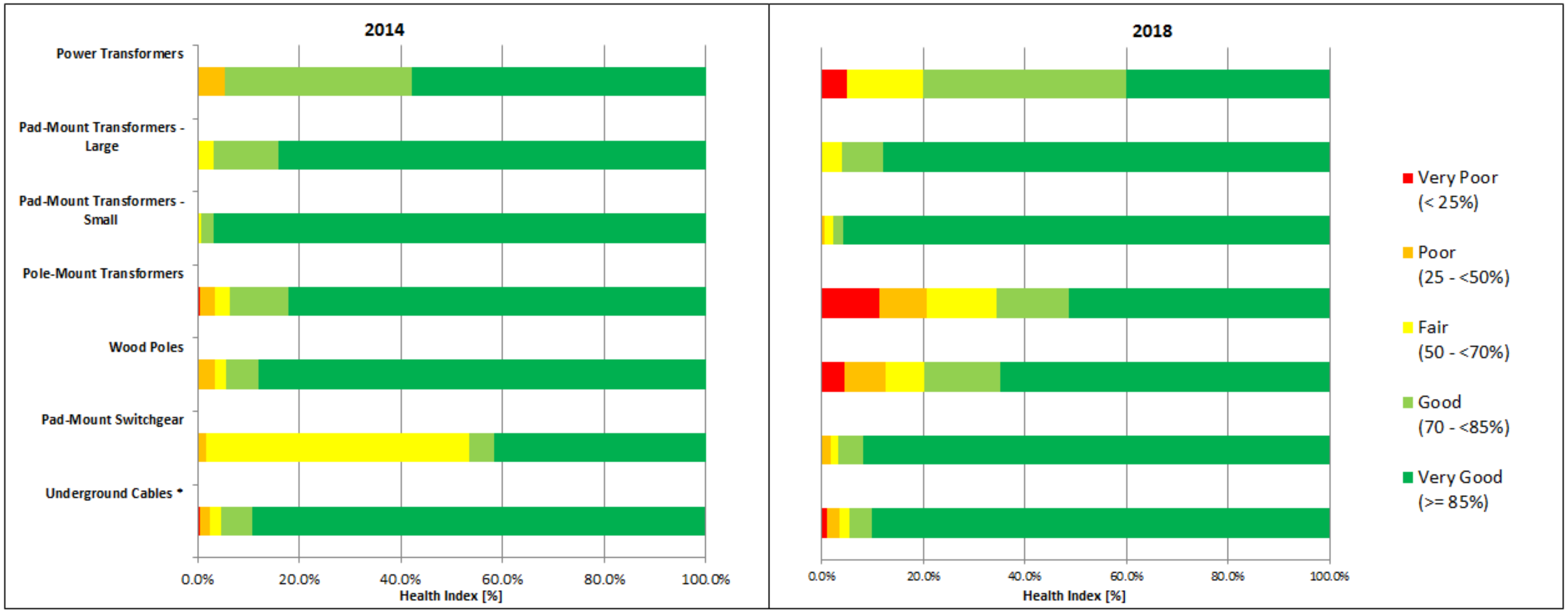

Figure 7 Change in Health Index Distribution

VI CONCLUSIONS AND RECOMMENDATIONS

1. An Asset Condition Assessment was conducted for NPEI's key distribution assets, namely power transformers, large pad-mounted transformers, small pad-mounted transformers, pole-top transformers, NPEI owned poles (wood, concrete, steel), non NPEI owned poles (wood, concrete, steel), pad-mounted switchgear, underground cables and overhead lines. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan was developed.

2. Pole-mounted transformers had the highest percentages of units in poor and very poor condition. More than 20% of its population was classified as poor to very poor. This asset category also has the lowest average Health Index, 74%, of all asset categories.

3. NPEI's most significant asset groups, in terms of number of units flagged for action in the near future, were pole-top transformers and wood poles. In year 1 it is estimated that 377 and 538 pole-top transformers and wood poles (NPEI and non NPEI altogether) respectively will require attention.

4. As only age and loading were available for pole-top transformers, it is recommended that information gathered from regular visual inspections be incorporated into the Health Indexing process.

5. Only age was available for underground cables. It is recommended that information gathered from visual inspections and ultrasonic and infrared scans be incorporated into the Health Index. Test data provides the best indicator of condition. If NPEI chooses to engage in cable testing, it is recommended that such data be incorporated into the Health Index. It is also recommended that NPEI collect age data for segments where age is not available, thus increasing this asset category's sample size.

6. An audit assessing the ACA changes between 2014 and 2018 was conducted. The following aspects were compared: Health Index Formulation, Population and Sample Size, Health Index Distribution. A total of seven asset groups were included. Overhead lines, which were first assessed in 2018 were not subject to the audit.

7. Between 2014 and 2018, the Health Index formulations for some asset categories were refined to include new data, age limiter curves, and/or refined condition criteria.

8. There were changes in the population of all asset groups. Reasons for such changes include decommissioning or installation of assets, as well as cleansing and validation of NPEI data.

9. NPEI has made significant strides in terms of improving the sample sizes. The sample sizes of 5 of the 7 asset groups included in the audit were 95% or higher. Between 2014 and 2018 the sample sizes for large pad-mounted transformers, wood poles and underground cables improved by 5%, 3%, and 10% respectively.

10. The population of pad-mounted switchgear increased more than double from 2014 to 2018, while the available data had little change, making the sample size drop substantially. The pad-mounted switchgear inventory needs to be verified by NPEI.

11. It is recommended that NPEI continue efforts to increase the sample size for each asset category.

12. There was a significant improvement in the overall health of pad-mounted switchgear. This is likely a result of new unit installations as well as the effective maintenance work during 2014-2018.

13. There was a significant decrease in the overall condition of pole-mounted transformers. Contributing factors may be the incorporation of loading and age limiter curve.

14. There was a significant decrease in the overall condition of wood poles. Contributing factors was the incorporation of much more age data.

15. It is important to note that the Flagged for Action plan presented in this study is based solely on asset condition as determined by available data. There are numerous other considerations that may influence NPEI's asset management plan. Among these are obsolescence, system growth, corporate priorities, technological advancements, etc.

APPENDIX A: RESULTS AND FINDINGS FOR EACH ASSET CATEGORY

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1 Power Transformers

1.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Power Transformers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

1.1.1 Condition and Sub-Condition Parameters

Table 1-1 Condition Parameters and Weights - Power Transformers

Condition Parameter			Sub-Condition Parameter			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Internals	5	1	H_2	5	Table 1-3
			2	CH_4 (Methane)	3	Table 1-3
			3	C_2H_6 (Ethane)	3	Table 1-3
			4	C_2H_4 (Ethylene)	3	Table 1-3
			5	C_2H_2 (Acetylene) Non-OLTC	5	Table 1-3
2	Insulation Oil	4	1	Power Factor (Doble)	2	Table 1-2
			2	Moisture	4	Table 1-2
			3	Dielectric Strength	5	Table 1-2
			4	Interfacial Tension	3	Table 1-2
			5	Acid Number	2	Table 1-2
			6	Color	1	Table 1-2
			7	Oxygen Inhibitor	1	Table 1-2
3	Insulation Paper	4	1	Furan Compound	**3**	Table 1-2
			2	Power Factor	**5**	Table 1-4
			3	DGA CO	2	Table 1-2
			4	DG CO_2	1	Table 1-2
4	Bushings	5	1	Bushing – Visual	**1**	Table 1-5
5	Tank	5	1	Paint - Visual	1	Table 1-5
			2	Oil Leak - Visual	1	Table 1-5
			3	Oil Containment - Visual	1	Table 1-5
6	Auxiliary	5	1	Heater - Visual	1	Table 1-5
7	Service Record	5	1	Loading	1	Table 1-6
	De-rating Factors				Table 1-7	
	Age Limiter Factor				Figure 1-1	

1.1.2 Condition Parameter Criteria

Oil Quality

Table 1-2 Oil Quality Test Criteria - Power Transformers

Score		4	3	2	1	0
Water Content (D1533) [ppm]	V ≤ 69	0	30	33.3	36.6	40
	69 < V < 230	0	20	25	30	35
	V ≥ 230	0	15	18.3	21.6	25
Dielectric Strength (D877) [kV]	V ≤ 69	40	36.6	33.3	30	0
	69 < V < 230	47	43	39	35	0
	V ≥ 230	50	46	43	40	0
IFT (D971) [dynes/cm]	V ≤ 69	25	21.6	18.3	15	0
	69 < V < 230	30	26	22	18	0
	V ≥ 230	32	28	24	20	0
Color	All	0	1.5	1.51	2	2.5
Acid Number (D974) [mg KOH/g]	V ≤ 69	0	0.05	0.1	0.15	0.2
	69 < V < 230	0	0.04	0.077	0.113	0.15
	V ≥ 230	0	0.03	0.053	0.076	0.1
Dissipation Factor (D924 - 25^{0}C)	All	0	0.5	1.0	1.5	2
Dissipation Factor (D924 - 100^{0}C)	All	0	5	10	15	20
Oxygen Inhibitor	All	0.08				0
Furan Compound	All	1000	800	450	250	0

Oil DGA

Table 1-3 Oil DGA Criteria - Power Transformers

Under 10 MVA or 10,000 liters of oil in tank						
Score	**4**	**3.2**	**2.4**	**1.6**	**0.8**	**0**
H2	0	6	12	18	24	30
CH4(Methane)	0	2	3	5	6	8
C2H6(Ethane)	0	1	2	3	4	5
C2H4(Ethylene)	0	3	6	8	11	14
C2H2(Acetylene)	0	15	30	45	60	75
CO	0	70	140	210	280	350
CO2	0	430	860	1290	1720	2150
10 - 100 MVA or 10,000 – 50,000 liters of oil in tank						
H2	0	52	104	156	208	260
CH4(Methane)	0	14	28	42	56	70
C2H6(Ethane)	0	9	18	27	36	45
C2H4(Ethylene)	0	33	66	99	132	165
C2H2(Acetylene)	0	1	2	3	4	5
CO	0	590	1180	1770	2360	2951
CO2	0	4500	9000	13500	18000	22505
> 100 MVA or > 50,000 liters of oil in tank						
H2	0	75	150	225	300	375
CH4(Methane)	0	49	98	147	196	245
C2H6(Ethane)	0	38	76	114	152	190
C2H4(Ethylene)	0	146	292	438	584	730
C2H2(Acetylene)	0	2	3	5	6	8
CO	0	1060	2120	3180	4240	5301
CO2	0	6870	13740	20610	27480	34357

Winding Power Dissipation Factor

Table 1-4 Power Dissipation Factor Test Criteria - Power Transformers

CPF	Description
4	%PF < 0.5%
3	0.5% < =%PF < 1%
2	1% < =%PF < 1.5%
1	1.5% <= %PF < 2.0%
0	%PF >= 2.0%

Inspections

Table 1-5 Inspection Score - Power Transformers

Score	Corrective Maintenance Count (CM) Value
4	CM < 3
3	3 ≤ CM < 6
2	6 ≤ CM < 9
1	9 ≤ CM < 12
0	CM ≥ 12

Where "Corrective Maintenance Count" is a function of the number and severity of correctives in a given year, calculated as below:

Corrective Maintenance Count = $\sum_i \left(\sum_j N_{ij} \times TW_j \right) \times YW_i$

Where:

N_{ij} = Number of problems/issues reported in the year "i" that are classified as type "j"

YW_i = Weight of problems/issues that occurred in year "i"

TW_j = Weight of problems/issues that are classified as having a type "j"

i	Year	Year Weight (YW_i)
1	2019	1
2	2018	0.9
3	2017	0.8
4	2016	0.7
5	2015	0.6
6	2014	0.5
7	2013	0.4
8	2012	0.3
9	2011	0.2
10	2010	0.1
11	2009	0
j	**Corrective Type**	**Type Weight (TW_j)**
1	High Pri Work	4
2	Med Pri Work	3
3	Low Pri Work	2
4	Monitor	1

Example: Sample Data set = { 2016: 1 – type "Med Pri Work", 1 type "Monitor";
2014: 2 – type "Low Pri Work"}

Corrective Maintenance Count = (1*3 + 1*1)*1 + (2*2)*0.8 = 7.2

Loading History

Table 1-6 Loading History - Power Transformers

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$

De-Rating Multiplier

The de-rating is based on the following equation and DR is described in the subsequent table.

$$DR = \min(DR_1, DR_2, DR_3)$$

Table 1-7 De-Rating Multiplier Criteria - Power Transformers

	1	**2**	**3**			
DR	**Oil Quality Moisture**	**Oil Quality Dielectric**	**TDCG**			
			Score =1	**Score = 2**	**Score = 3**	**Score =4**
0.9	-	-	Daily increase rate >= 30%	Daily increase rate >=10%	-	-
0.75	-	-	-	Daily increase rate >=30%	Daily increase rate >=10%	-
0.5	Moisture score =1	Dielectric score =1	-	-	Daily increase rate >=30%	Daily increase rate >=10%
0.25	Moisture score = 0	Dielectric score = 0	-	-	-	Daily increase rate >=30%

Where

Score	**1**	**2**	**3**	**4**
TDCG	0	`720	1920	4630

Age Limiting Factor

In this project, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. Principle of applying the degradation survival curve is described in section II.2.1.

In this project, the parameters of Power Transformers age limiting curve are shown in the following table, based on industry practice.

Table 1-8 Age Limiting Curve Parameters - Power Transformers

Asset Type	α	β
Power Transformers	**55.6**	**14.35**

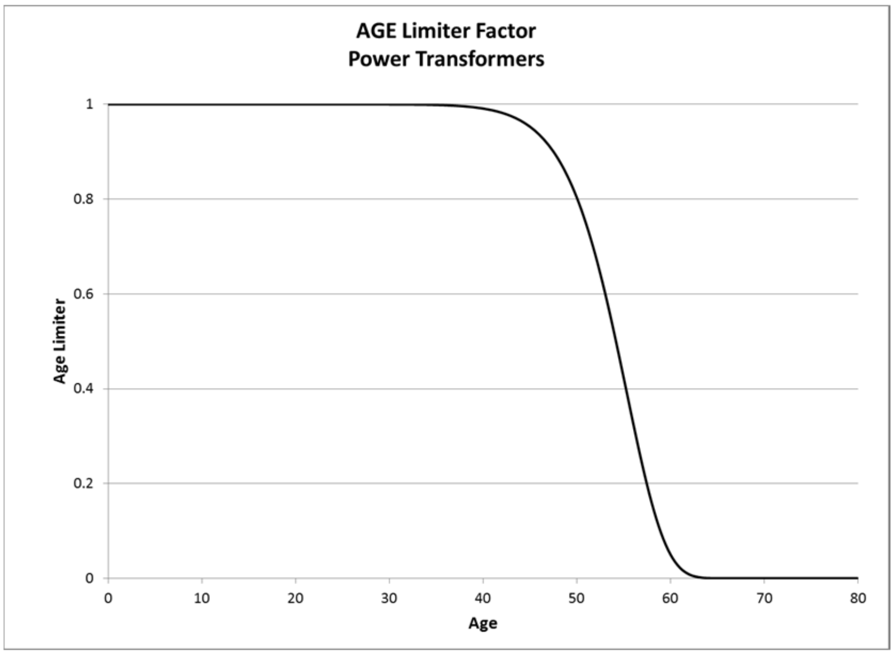

Figure 1-1 Age Limiting Factor Criteria - - Power Transformers

1.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 27 years.

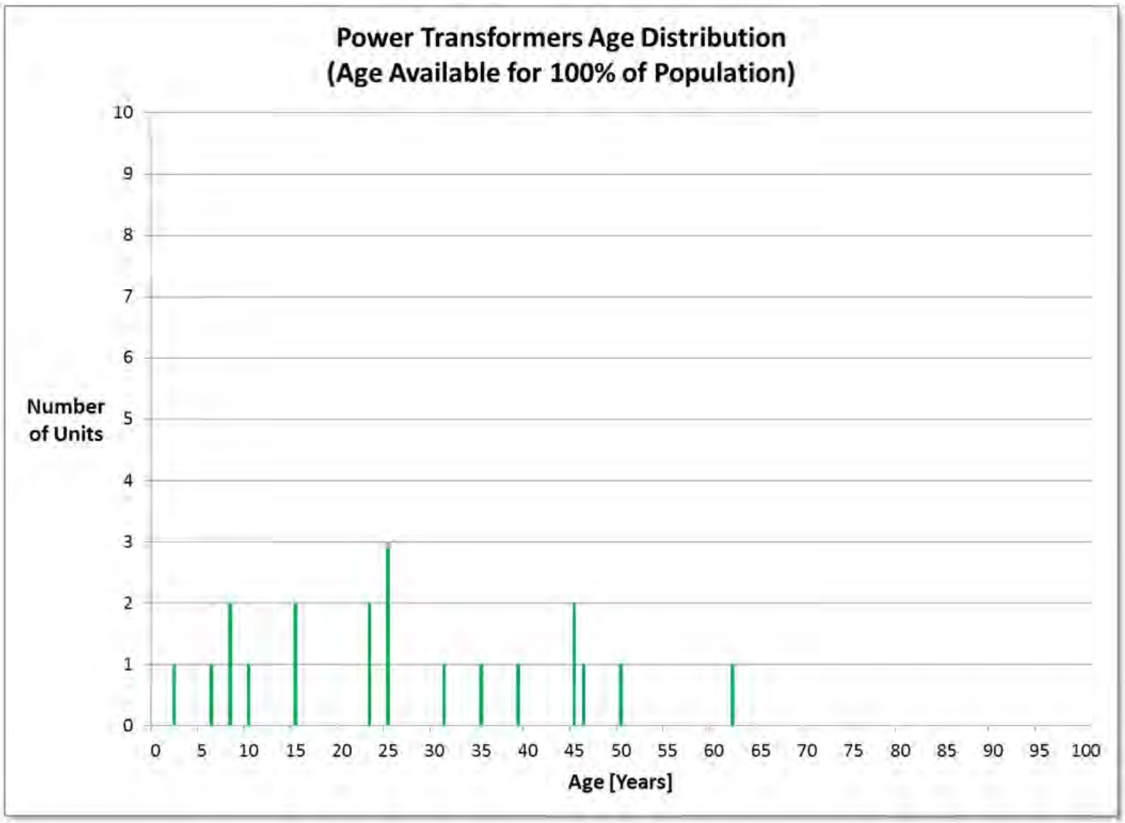

Figure 1-2 Power Transformers Age Distribution

1.3 Health Index Results

At the time of assessment, there were 20 in service Power Transformers at NPEI. All of them had sufficient data for assessment.

The average Health Index for this asset group is 77%. It was found 5% of the samples were in very poor condition.

The Health Index Distribution is shown in Figure 1-3.

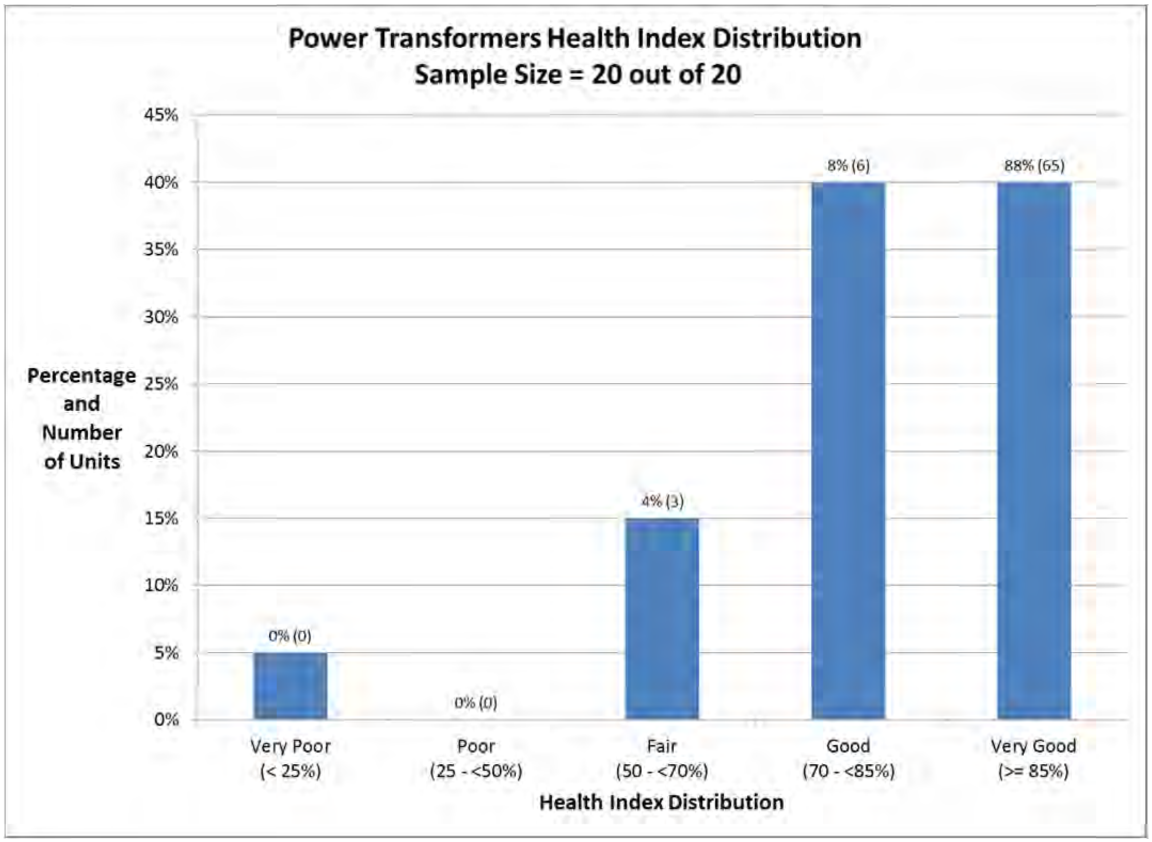

Figure 1-3 Health Index Distribution - Power Transformers

1.4 Condition-Based Flagged for Action Plan

It is assumed that Power Transformers are proactively addressed. Based on current condition (Health Index) of Power Transformers and that the assumption that the rate of aging is constant (i.e. units do not continue to degrade faster than what would be typical), the Flagged for Action Plan is as follows. Because only one unit is flagged in current year, levelization is not required.

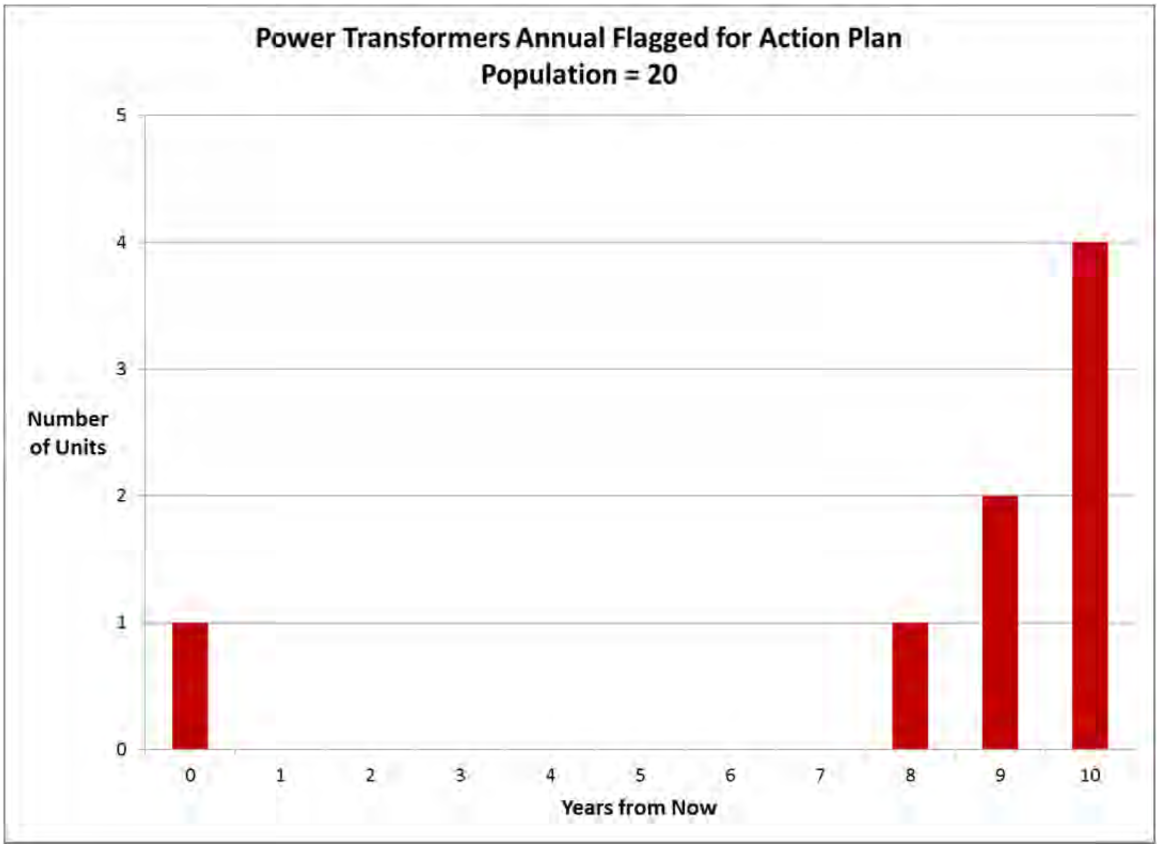

Figure 1-4 Condition-Based Flagged for Action Plan - Power Transformers

The detailed results, from lowest to highest Health Index are shown below:

Table 1-9 Results for Each Power Transformers Unit

TC	Station Name	Age	Transformer Data Availability	Transformer Health Index	Transformer Health Index Category	Flagged for Action (Years from now)
24	VIRGINIA ST STATION	62	17.7%	0.8%	Very Poor	0
31	MARGARET A-127	46	20.1%	59.9%	Fair	8
38	LEWIS A-119	35	20.1%	64.4%	Fair	9
25	SWAYZEDRV A-145	25	18.1%	65.2%	Fair	9
21	STATION 23 DORCHESTER ROAD	50	17.8%	71.9%	Good	10
35	ALLENDALE A-175	39	19.8%	72.8%	Good	10
44	PARK STREET A-33	25	18.1%	70.3%	Good	10
147	PELHAM ST	10	17.4%	74.7%	Good	10
45	ONTARIO STATION #3	31	16.3%	77.0%	Good	11
78	SMITHVILLE DS	8	15.5%	78.6%	Good	11
144	GREEN LANE DS	6	18.6%	78.3%	Good	11
23	STATION 17 VIRGINIA ST	25	20.1%	80.7%	Good	12
40	ARMOURY A-113	45	18.6%	88.1%	Very Good	13
30	PEW ST	23	15.8%	86.5%	Very Good	13
32	DRUMMOND A-122	23	20.1%	86.5%	Very Good	13
39	ARMOURY ST A-113	45	21.8%	89.4%	Very Good	14
28	KALALTS	15	21.1%	91.2%	Very Good	14
29	KALAR	15	22.3%	94.8%	Very Good	16
148	PORTABLE SUB	8	4.5%	100.0%	Very Good	>20
159	STATION ST DS	2	12.3%	100.0%	Very Good	>20

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1.5 Data Analysis

The type of data available for power transformers include loading, oil quality, dissolved gas analysis, and power dissipation factor tests, as well as age and inspections related to bushing, leaks, tank condition, and connections.

1.5.1 Data Gaps

All of the critical data, namely oil quality and DGA, winding power dissipation factor and inspections are available and included in the Health Index formula.

A few parameters that can be included in the Health Index formula follow.

Table 1-10 Data Gaps - Power Transformers

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Turn Ratio	Winding	☆☆	Winding turns	Ratio deviated from benchmark	On-site Test
Winding		☆	Winding physical	Physical degradation/damage	Visual Inspection
Excitation Current		☆	Magnetizing circuit	Variations between readings	On-site Test
Leakage Reactance		☆	Winding leaked flux	Ratio deviated from benchmark	On-site Test
Capacitance	Paper Insulation	☆☆	Insulation	Variations between readings	On-site Test
Bushing Oil Level	Bushing	☆	Bushing oil	Low oil level	Visual Inspection
Bushing		☆☆	Bushing physical	Physical degradation/damage	
Core	Core	☆	Iron core	Physical degradation/damage	Visual Inspection
Grounding		☆	Core grounding		
Radiators	Cooling	☆	Temperature control	Physical degradation/damage	Visual Inspection
Valves		☆			
Vents		☆			
Fans		☆			
Pumps	Pump	☆	Oil pump	Physical degradation/damage	On-site Test
Breathers	Conservator	☆	Gel desiccant	Desiccant color change	Visual Inspection
Pads	Auxiliary	☆	Foundation	Physical degradation/damage	Visual Inspection
Gauges		☆	Temp Gauge		
Alarms		☆	Signalization		

1.5.2 Data Availability Distribution

Nearly all units had age, loading, oil quality, and DGA tests, and some inspection records available.

The average DAI for Power Transformers, as measured against the existing Health Index formula/data set, is 61%.

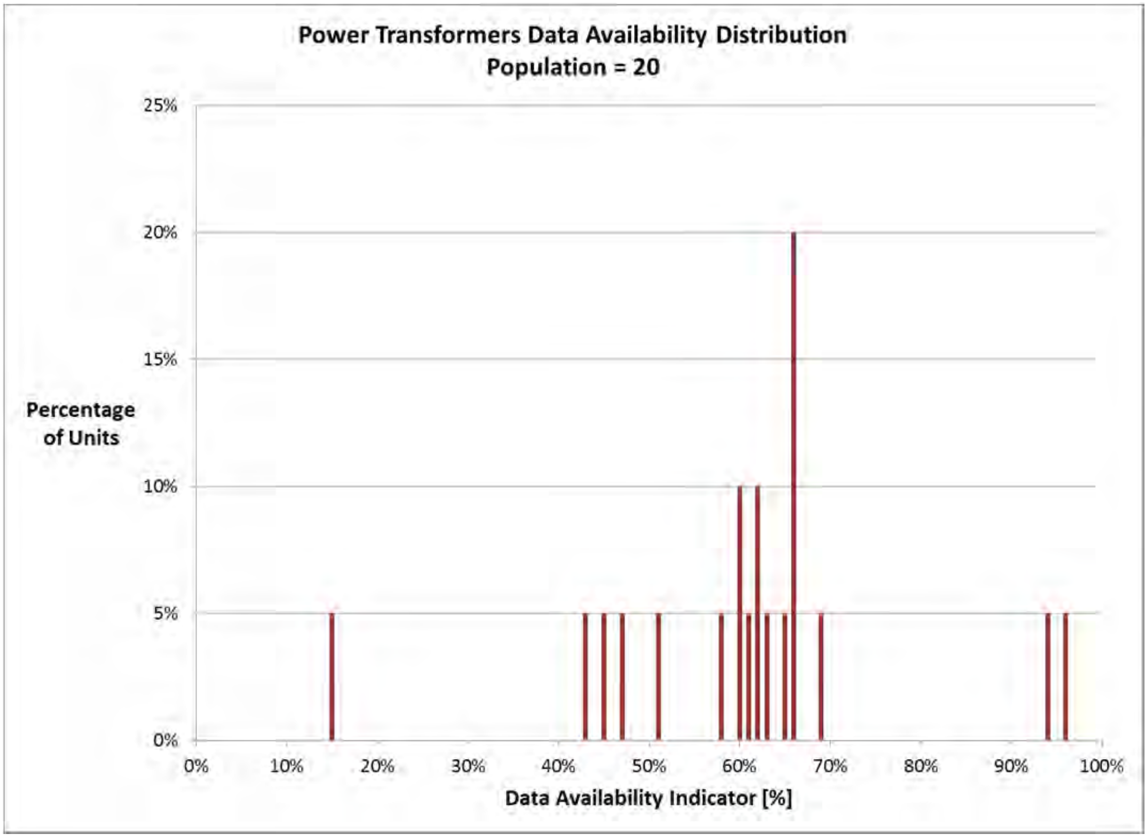

Figure 1-5 Data Availability Distribution - Power Transformers

2 Large Pad-Mount Transformers

2.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Large Pad-Mount Transformers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

2.1.1 Condition and Sub-Condition Parameters

Table 2-1 Condition Parameters and Weights - Large Pad-Mount Transformers

Condition Parameter			Sub-Condition Parameter			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Physical Condition	3	1	Tank Corrosion	3	Table 2-4
			2	Access	1	Table 2-4
			3	Base	2	Table 2-4
2	Insulation	6	1	Oil Quality	3	Table 2-2
			2	Oil DGA	6	Table 2-3
			3	Insulator	1	Table 2-4
3	Connection	2	1	Oil Leak	2	Table 2-4
			2	Elbow	4	Table 2-4
			3	Grounding	1	Table 2-4
			4	Connection	4	Table 2-4
4	Service Record	3	1	Overall	2	Table 2-4
			2	Loading	1	Table 2-5
	Age Limiting factor					Figure 2-1

2.1.2 Condition Parameter Criteria

<u>Oil Quality</u>

Table 2-2 Oil Quality Test Criteria - Large Pad-Mount Transformers

CPF	Description
4	Overall factor is less than 1.2
3	Overall factor between 1.2 and 1.5
2	Overall factor is between 1.5 and 2.0
1	Overall factor is between 2.0 and 3.0
0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

Oil Quality Test	Voltage Class [kV]	Scores				
		1	2	3	4	Weight
Water Content (D1533) [ppm]	V ≤ 69	< 30	30-35	35-40	> 40	5
	69 < V < 230	< 20	20-25	25-30	> 35	
	V ≥ 230	< 15	15-20	20-25	> 25	
Dielectric Strength (D1816 - 2 mm gap) [kV]	V ≤ 69	> 40	35-40	30-35	< 30	4
	69 < V < 230	> 47	42-47	35-42	< 35	
	V ≥ 230	> 50	50-45	40-45	< 40	
Dielectric Strength (D877) [kV]	All	> 40	30-40	20-30	< 20	
IFT (D971) [dynes/cm]	V ≤ 69	> 25	20-25	15-20	< 15	4
	69 < V < 230	> 30	23-30	18-23	< 18	
	V ≥ 230	> 32	25-32	20-25	< 20	
Color	All	< 1.5	1.5-2.0	2.0-2.5	> 2.5	1
Acid Number (D974) [mg KOH/g]	V ≤ 69	< 0.05	0.05-0.01	0.1-0.2	> 0.2	4
	69 < V < 230	< 0.04	0.04-0.1	0.1-0.15	> 0.15	
	V ≥ 230	< 0.03	0.03-0.07	0.07-0.1	> 0.1	
Dissipation Factor (D924 - 25^{0}C)	All	< 0.5%	0.5%-1%	1-2%	> 2%	5
Dissipation Factor (D924 - 100^{0}C)	All	< 5%	5%-10%	10%-20%	> 20%	

Overall Factor = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

For example if all data is available, overall Factor = $\frac{\sum Score_i \times Weight_i}{12}$

Oil DGA

Table 2-3 Oil DGA Criteria - Large Pad-Mount Transformers

CPF	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

*NOTE: In the case of a score other than 4, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

Where the DGA overall factor is the weighted average of the following gas scores:

2.5 MVA to Under 10 MVA

Dissolved Gas	Scores						
	1	**2**	**3**	**4**	**5**	**6**	**Weight**
H2	<=70	<=100	<=200	<=400	<=1000	>1000	**4**
CH4(Methane)	<=70	<=120	<=200	<=400	<=600	>600	**3**
C2H6(Ethane)	<=75	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=60	<=100	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=100	>100	**5**
CO	<=750	<=1000	<=1300	<=1500	<=1700	>2000	**4***
CO2	<=7500	<=8500	<=9000	<=12000	<=15000	>15000	**4***
CO2/CO	3 - <10	<12	<15 Or <3	<18	<20	>20	**4***

*If CO ≥ 500 ppm and CO2 ≥ 5000 ppm, use CO2/CO ratio (e.g. CO and CO2 weights = 0, CO2/CO weight = 4)
If CO < 500 ppm and CO2 < 5000 ppm, use CO2 and CO limits (e.g. CO and CO2 weights = 4, CO2/CO weight = 0)

10 MVA and Higher

Dissolved Gas	Scores						
	1	**2**	**3**	**4**	**5**	**6**	**Weight**
H2	<=40	<=100	<=300	<=500	<=1000	>1000	**4**
CH4(Methane)	<=80	<=150	<=200	<=500	<=700	>700	**3**
C2H6(Ethane)	<=70	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=60	<=100	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	**5**
CO	<=350	<=500	<=600	<=1000	<=1500	>1500	**4***
CO2	<=3000	<=4500	<=5700	<=7500	<=10000	>12000	**4***
CO2/CO	3 - <8	< 10	<13 Or <3	<14	<15	>15	**4***

*If CO ≥ 500 ppm and CO2 ≥ 5000 ppm, use CO2/CO ratio (e.g. CO and CO2 weights = 0, CO2/CO weight = 4)
If CO < 500 ppm and CO2 < 5000 ppm, use CO2 and CO limits (e.g. CO and CO2 weights = 4, CO2/CO weight = 0)

Overall Factor = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight}$

Inspections

Table 2-4 Inspection Score - Large Pad-Mount Transformers

CPF	Tank Corrosion	Access	Leak / Insulator	Elbow / Connection / Overall	Grounding
0	Rust, Repair	Vegetation		Fail	4, 5
1	Graffiti	Fence, Landscaping			3
2			Other		2
3					1
4	Good	Okay	Okay	Pass	0

Loading History

Table 2-5 Loading History - Large Pad-Mount Transformers

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$

Age Limiting Factor

In this project, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. Principle of applying the degradation survival curve is described in section II.2.1.

In this project, the parameters of Large Pad-Mount Transformers age limiting curve are shown in the following table, based on industry practice.

Table 2-6 Age Limiting Curve Parameters - Large Pad-Mount Transformers

Asset Type	α	β
Pad Mounted Transformers	**50.5544**	**6.4053**

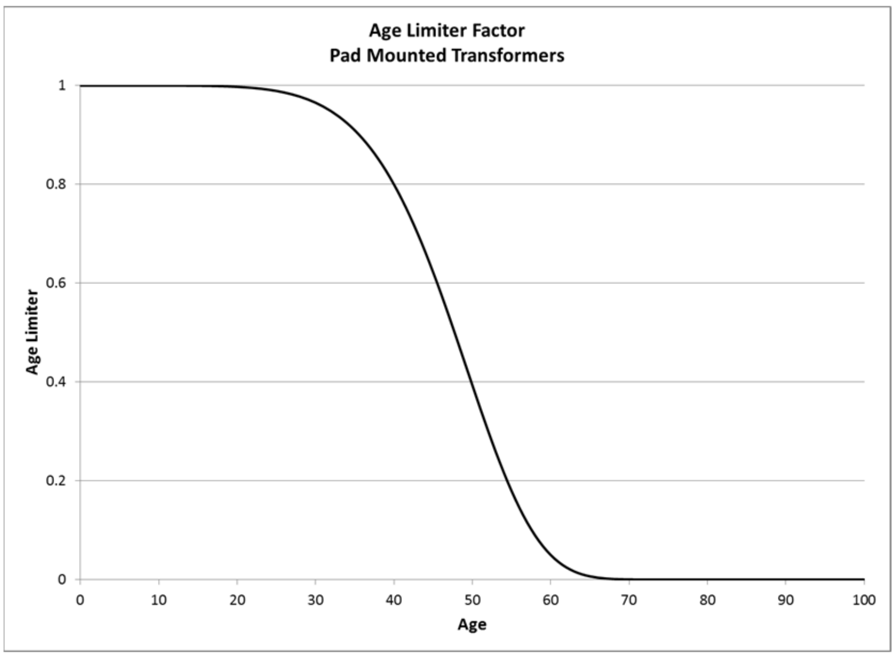

Figure 2-1 Age Limiting Factor Criteria - - Large Pad-Mount Transformers

2.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 15 years.

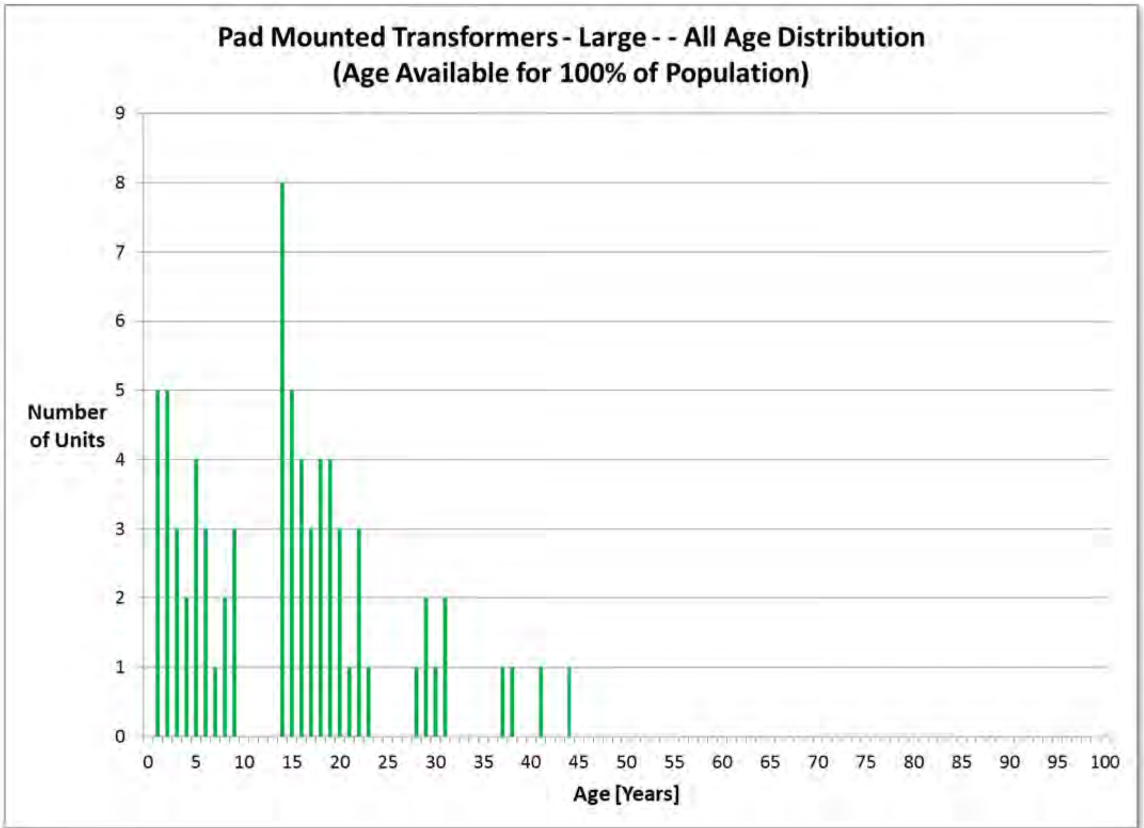

Figure 2-2 Age Distribution - Large Pad-Mount Transformers

2.3 Health Index Results

At the time of assessment, there were 75 in service Large Pad-Mount Transformers at NPEI. All of them had sufficient data for assessment.

The average Health Index for this asset group is 95%. None of the samples were in poor or very poor condition.

The Health Index Distribution is shown in below.

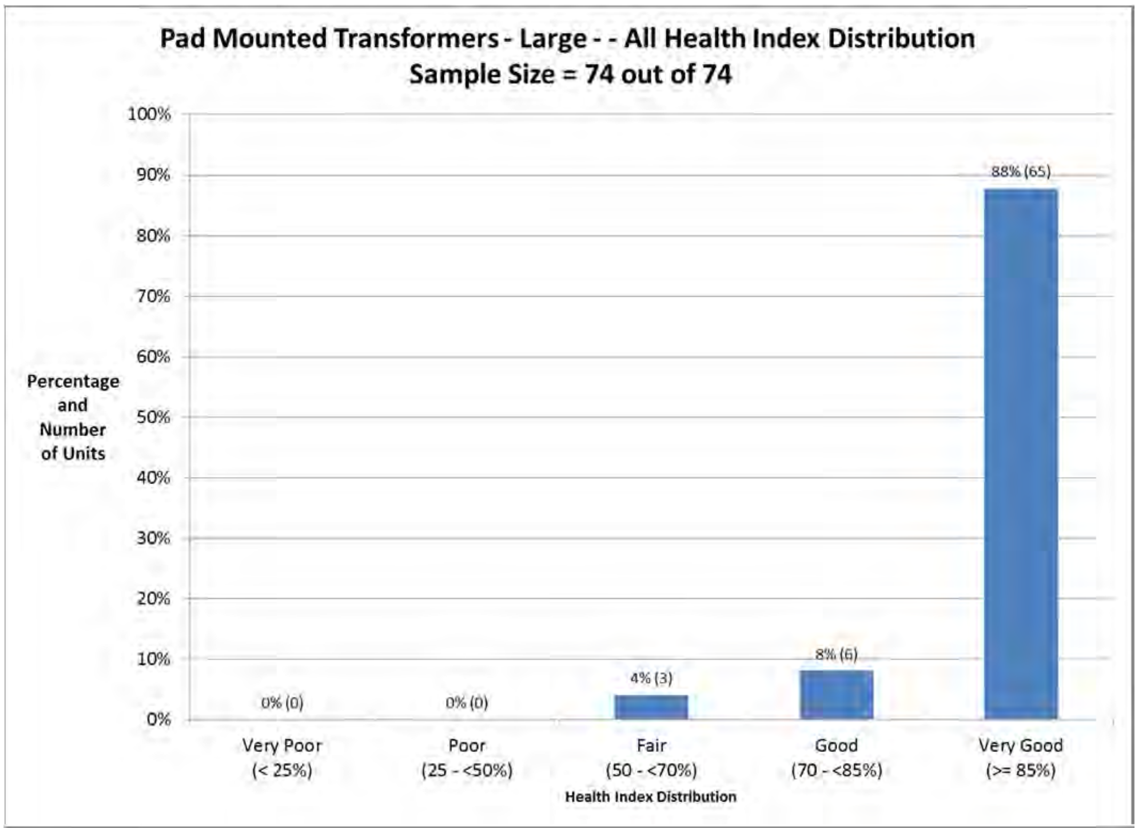

Figure 2-3 Health Index Distribution - Large Pad-Mount Transformers

2.4 Condition-Based Flagged for Action Plan

While Large Pad-Mount Transformers are proactively and reactively addressed, the proactive approach was used in estimating the Flagged for Action Plan. Based on current condition (Health Index) of Large Pad-Mount Transformers and that the assumption that the rate of aging is constant (i.e. units do not continue to degrade faster than what would be typical), there is no unit flagged for action in the next 10 years.

The detailed results, from lowest to highest Health Index are shown below:

Table 2-7 Results for Each Large Pad-Mount Transformers Unit

Transformer	Station Name	Age	Transformer Data Availability	Transformer Health Index	Transformer Health Index Category	Flagged for Action (Years from now)
800105	NIAGARA FALLS CASTING	44	63.6%	56.3%	Fair	>20
800753		3	38.6%	56.7%	Fair	>20
800126		38	63.6%	64.6%	Fair	>20
800413	SUPER EIGHT MOTEL	22	100.0%	73.8%	Good	>20
800532	LUNDY'S LANE OUTLET MALL	16	100.0%	74.0%	Good	>20
800147	EVENTIDE HOME	37	54.3%	75.6%	Good	>20
800135		41	61.4%	77.0%	Good	>20
800546	N.F. COMMUNITY CENTRE	15	100.0%	83.6%	Good	>20
800430	TANGLEWOOD	21	100.0%	84.9%	Good	>20
800414	COURTYARD MARRIOTT	22	100.0%	86.5%	Very Good	>20
800586		14	100.0%	86.5%	Very Good	>20
800490	GOLDEN HORSESHOE VENTURES	18	100.0%	93.2%	Very Good	>20
800526	DAY'S INN	16	100.0%	93.2%	Very Good	>20
800589		14	92.9%	93.2%	Very Good	>20
PW800984		31	0.0%	95.7%	Very Good	>20
800127	DAYS INN	31	7.1%	95.7%	Very Good	>20
800197	PROV. CRANE	30	61.4%	96.5%	Very Good	>20
PW800954		29	0.0%	97.2%	Very Good	>20
800210	MANSIONS OF FOREST GLEN CONDO'S	29	61.4%	97.2%	Very Good	>20
PW10716		28	0.0%	97.8%	Very Good	>20
800465	AMERICANA MOTEL	19	100.0%	96.7%	Very Good	>20

Transformer	Station Name	Age	Transformer Data Availability	Transformer Health Index	Transformer Health Index Category	Flagged for Action (Years from now)
PW800995		23	0.0%	99.4%	Very Good	>20
PW800999		22	0.0%	99.5%	Very Good	>20
PW8461		20	0.0%	99.7%	Very Good	>20
PW800985		20	0.0%	99.7%	Very Good	>20
PW800965		20	0.0%	99.7%	Very Good	>20
PW800978		19	0.0%	99.8%	Very Good	>20
PW800939		19	0.0%	99.8%	Very Good	>20
PW800917		19	0.0%	99.8%	Very Good	>20
PW800932		18	0.0%	99.9%	Very Good	>20
PW800923		18	0.0%	99.9%	Very Good	>20
PW801000		18	0.0%	99.9%	Very Good	>20
PW800981		17	0.0%	99.9%	Very Good	>20
PW800940		17	0.0%	99.9%	Very Good	>20
800515	DOUBLE TREE	17	7.1%	99.9%	Very Good	>20
PW800935		16	0.0%	99.9%	Very Good	>20
PW800937		16	0.0%	99.9%	Very Good	>20
PW800994		15	0.0%	100.0%	Very Good	>20
PW800924		15	0.0%	100.0%	Very Good	>20
800550		15	45.7%	100.0%	Very Good	>20
800554	REGIONAL BIO SOLIDS	15	54.3%	99.7%	Very Good	>20
PW801001		14	0.0%	100.0%	Very Good	>20
800588		14	92.9%	99.7%	Very Good	>20
800585		14	92.9%	99.7%	Very Good	>20
800584		14	92.9%	99.7%	Very Good	>20
800568		14	100.0%	99.7%	Very Good	>20

Transformer	Station Name	Age	Transformer Data Availability	Transformer Health Index	Transformer Health Index Category	Flagged for Action (Years from now)
800587		14	100.0%	99.7%	Very Good	>20
800661		9	100.0%	99.4%	Very Good	>20
800662		9	100.0%	99.4%	Very Good	>20
800660		9	100.0%	99.7%	Very Good	>20
800666		8	100.0%	99.4%	Very Good	>20
800674		8	100.0%	99.7%	Very Good	>20
800699		7	100.0%	99.7%	Very Good	>20
800716		6	45.7%	100.0%	Very Good	>20
800709		6	45.7%	100.0%	Very Good	>20
800710		6	100.0%	99.7%	Very Good	>20
PW801040		5	0.0%	100.0%	Very Good	>20
PW801041		5	0.0%	100.0%	Very Good	>20
800717		5	45.7%	100.0%	Very Good	>20
800727		5	92.9%	99.4%	Very Good	>20
800734		4	38.6%	100.0%	Very Good	>20
800733		4	45.7%	100.0%	Very Good	>20
PW801050		3	0.0%	100.0%	Very Good	>20
800757		3	100.0%	99.4%	Very Good	>20
PW801058		2	0.0%	100.0%	Very Good	>20
PW801054		2	0.0%	100.0%	Very Good	>20
PW801061		2	0.0%	100.0%	Very Good	>20
800781		2	7.1%	100.0%	Very Good	>20
800780		2	38.6%	100.0%	Very Good	>20
PW801069		1	0.0%	100.0%	Very Good	>20
PW801065		1	0.0%	100.0%	Very Good	>20

Transformer	Station Name	Age	Transformer Data Availability	Transformer Health Index	Transformer Health Index Category	Flagged for Action (Years from now)
800796		1	0.0%	100.0%	Very Good	>20
800788		1	7.1%	100.0%	Very Good	>20
800792		1	7.1%	100.0%	Very Good	>20

2.5 Data Analysis

The type of data available for large pad-mounted transformers include oil quality and dissolved gas analysis, as well as age and limited inspection records related to tank condition and leaks. More detailed inspections were not available for this asset group.

2.5.1 Data Gaps

Additionally, parameters that can be included in the Health Index formula follow.

Table 2-8 Data Gaps - Large Pad-Mount Transformers

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Bushing	Connection	☆☆	Bushing	Visible issues	Visual Inspection

2.5.2 *Data Availability Distribution*

Nearly all units had age. A subset of units had oil quality, and DGA tests, and some inspection records available. The average DAI for Large Pad-Mount Transformers, as measured against the existing Health Index formula/data set, is 43%.

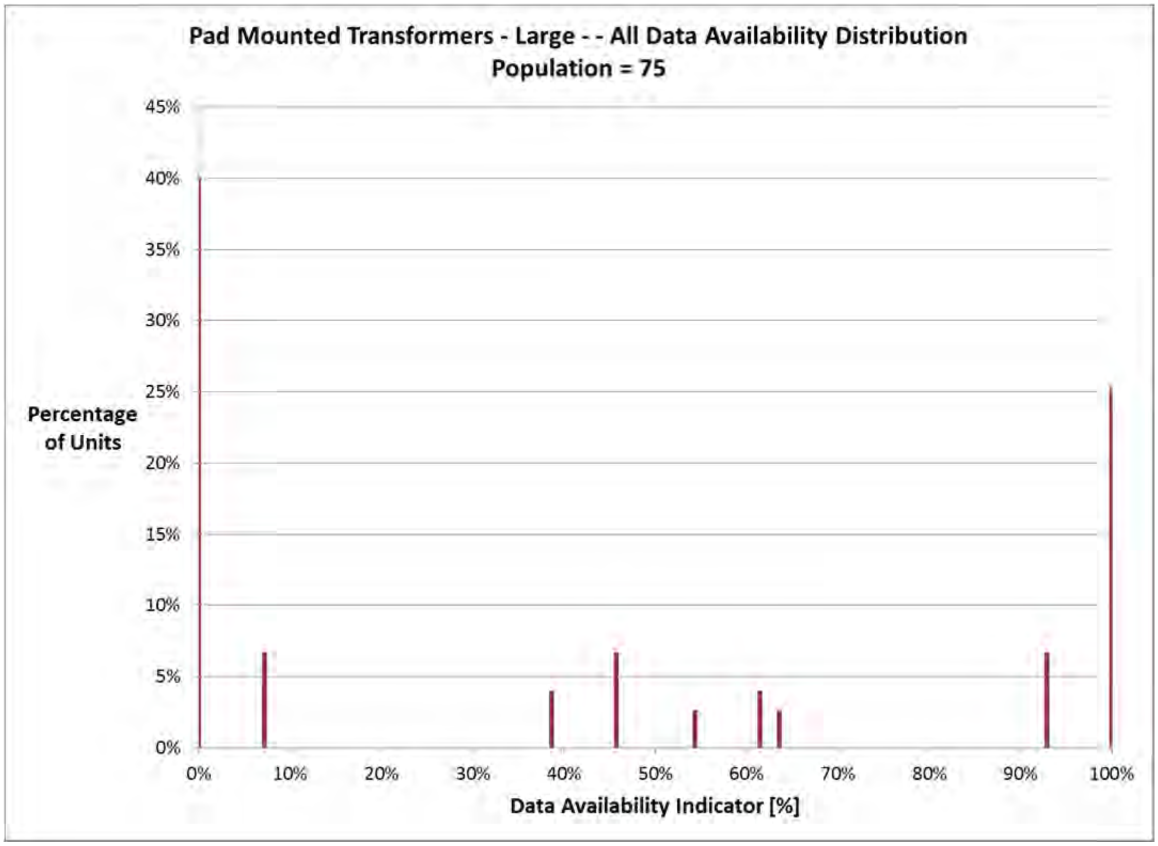

Figure 2-4 Data Availability Distribution - Large Pad-Mount Transformers

3 Small Pad-Mount Transformers

3.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Small Pad-Mount Transformers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

3.1.1 Condition and Sub-Condition Parameters

Table 3-1 Condition Parameters and Weights - Small Pad-Mount Transformers

Condition Parameter			Sub-Condition Parameter			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Physical Condition	3	1	Tank Corrosion	3	Table 3-2
			2	Access	1	Table 3-2
			3	Base	2	Table 3-2
2	Connection	5	1	Oil Leak	2	Table 3-2
			2	Elbow	4	Table 3-2
			3	Grounding	1	Table 3-2
			4	Connection	4	Table 3-2
			5	Insulator	1	Table 3-2
3	Service Record	5	1	Overall	2	Table 3-2
			2	Loading	1	Table 3-3
	Age Limiting factor					Figure 3-1

3.1.2 Condition Parameter Criteria

Inspections

Table 3-2 Inspection Score - Small Pad-Mount Transformers

CPF	Tank Corrosion	Access	Leak / Insulator	Elbow / Connection / Overall	Grounding
0	Rust, Repair	Vegetation		Fail	4, 5
1	Graffiti	Fence, Landscaping			3
2			Other		2
3					1
4	Good	Okay	Okay	Pass	0

Loading History

Table 3-3 Loading History - Small Pad-Mount Transformers

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$

Age Limiting Factor

In this project, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. Principle of applying the degradation survival curve is described in section II.2.1.

In this project, the parameters of Small Pad-Mount Transformers age limiting curve are shown in the following table, based on NPEI historic removal data.

Table 3-4 Age Limiting Curve Parameters - Small Pad-Mount Transformers

Asset Type	α	β
Pad Mounted Transformers	**69.81**	**6.4053**

Figure 3-1 Age Limiting Factor Criteria - - Small Pad-Mount Transformers

3.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 99% of the population. The average age was found to be 17 years.

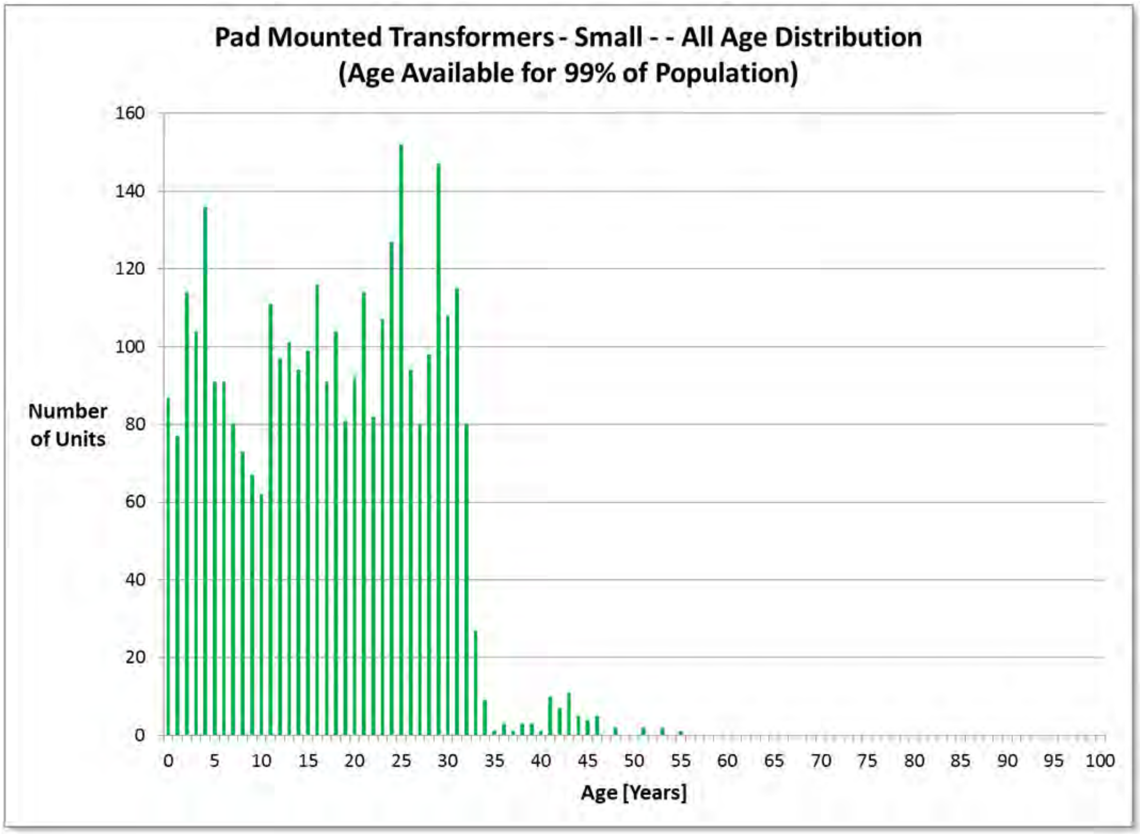

Figure 3-2 Age Distribution - Small Pad-Mount Transformers

3.3 Health Index Results

At the time of assessment, there were 3391 in service Small Pad-Mount Transformers at NPEI. Of these, 3369 units had sufficient data for assessment.

The average Health Index for this asset group is 96%. In total 14 units of the samples were in poor or very poor condition.

The Health Index Distribution is shown in below.

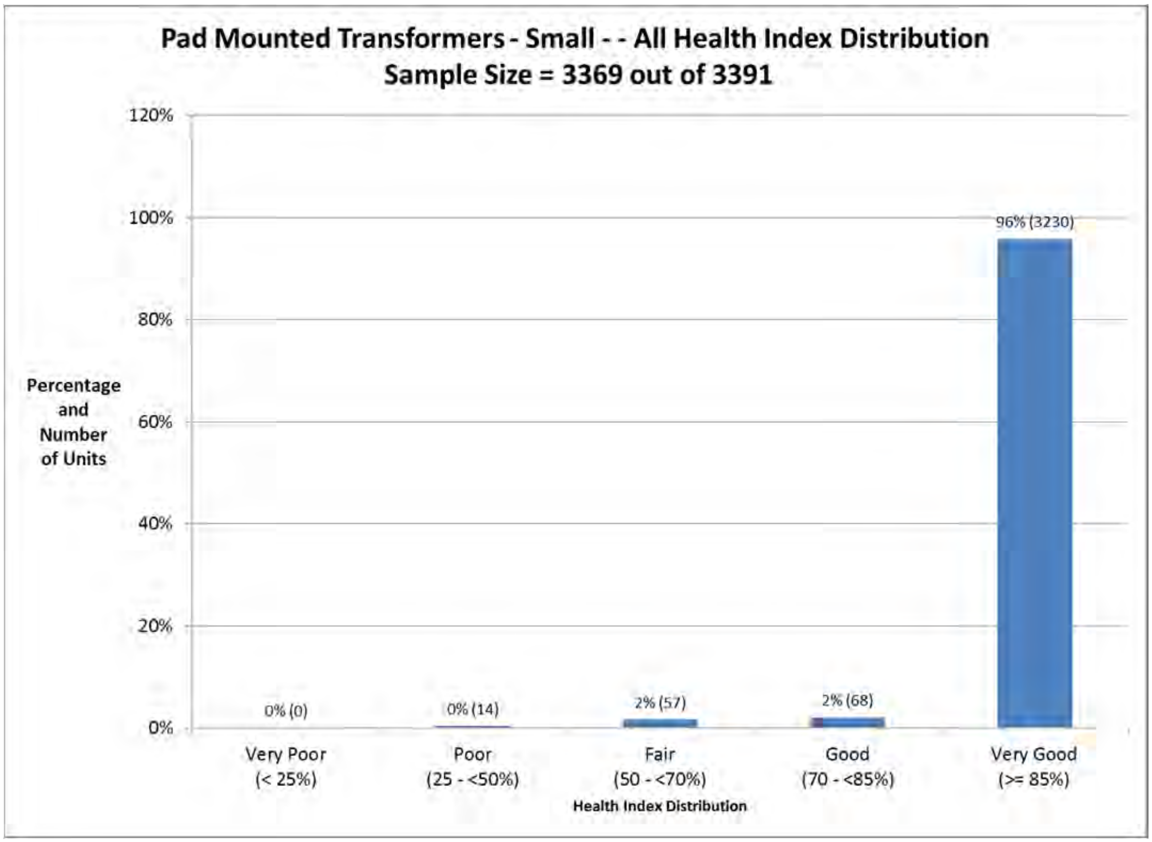

Figure 3-3 Health Index Distribution - Small Pad-Mount Transformers

3.4 Condition-Based Flagged for Action Plan

While Small Pad-Mount Transformers are proactively and reactively addressed, the proactive approach was used in estimating the Flagged for Action Plan. Based on current condition (Health Index) of Small Pad-Mount Transformers and that the assumption that the rate of aging is constant (i.e. units do not continue to degrade faster than what would be typical), the Flagged for Action plan in the next 10 years is shown below.

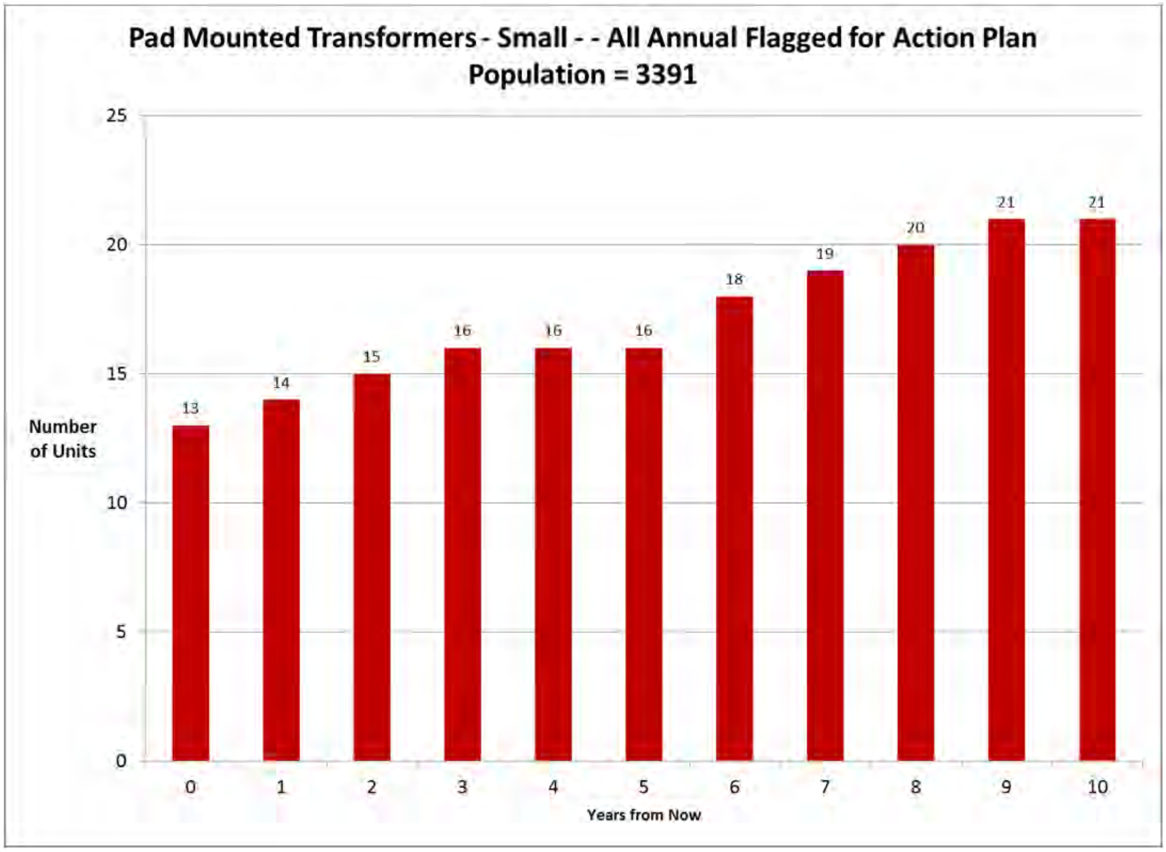

Figure 3-4 Flagged for Action Plan - Small Pad-Mount Transformers

3.5 Data Analysis

The type of data available for large pad-mounted transformers include oil quality and dissolved gas analysis, as well as age and limited inspection records related to tank condition and leaks. More detailed inspections were not available for this asset group.

3.5.1 Data Gaps

Additionally, parameters that can be included in the Health Index formula follow.

Table 3-5 Data Gaps - Small Pad-Mount Transformers

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Bushing	Connection	☆☆	Bushing	Visible issues	Visual Inspection
Oil Quality	Insulation	☆☆☆	Insulation oil	Insulation properties abnormal	Sample test
Oil DGA		☆☆☆	Insulation oil	Dissolved gas higher than normal	

3.5.2 Data Availability Distribution

Nearly all units had age. A subset of units had some inspection records available. The average DAI for Small Pad-Mount Transformers, as measured against the existing Health Index formula/data set, is 57%.

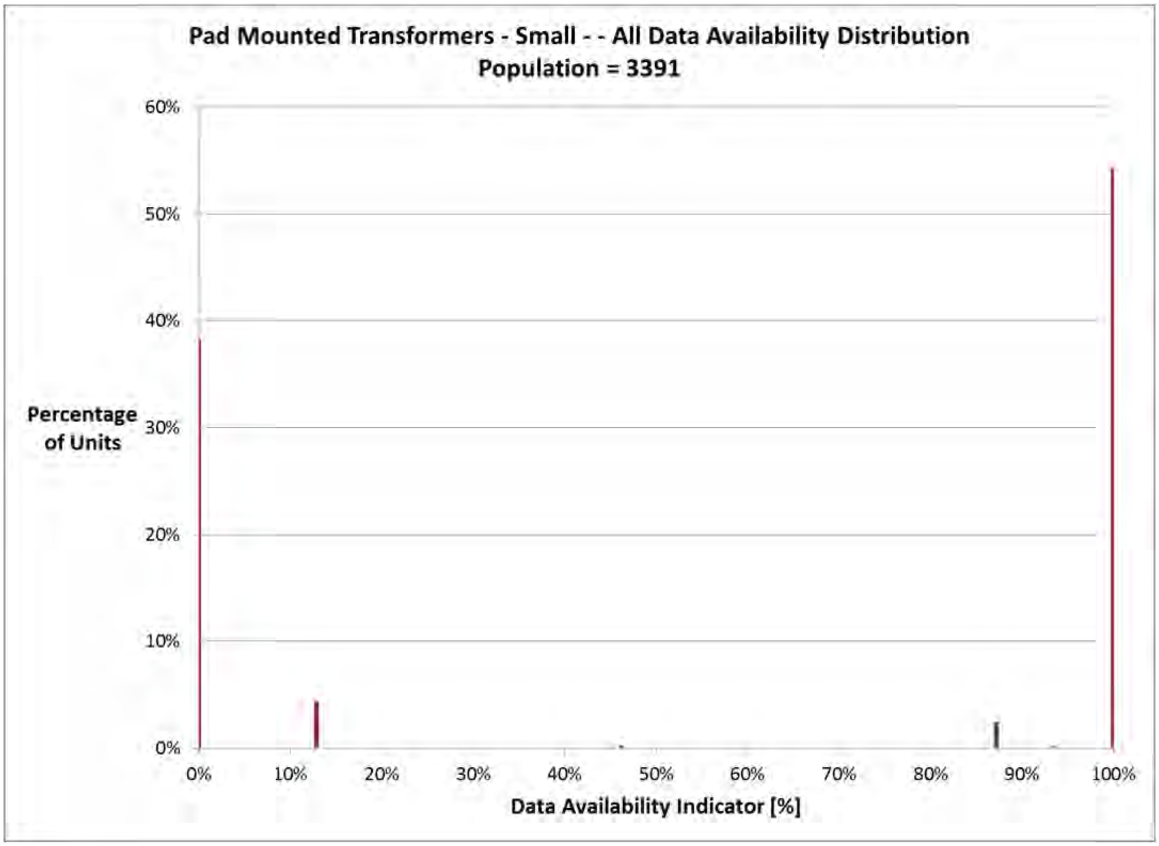

Figure 3-5 Data Availability Distribution - Small Pad-Mount Transformers

4 Pole-Mounted Transformers

4.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Pole-Mounted Transformers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

4.1.1 Condition and Sub-Condition Parameters

Table 4-1 Condition Parameters and Weights - Pole-Mounted Transformers

Condition Parameter			Sub-Condition Parameter			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Service Record	1	1	Loading	1	Table 4-2
	Age Limiter Factor					Figure 4-1

4.1.2 Condition Parameter Criteria

<u>Loading History</u>

Table 4-2 Loading History - Pole-Mounted Transformers

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$

Age Limiting Factor

In this project, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. Principle of applying the degradation survival curve is described in section II.2.1.

In this project, the parameters of Pole-Mounted Transformers age limiting curve are shown in the following table, based on NPEI historic removal data.

Table 4-3 Age Limiting Curve Parameters - Pole-Mounted Transformers

Asset Type	α	β
Pole-Mounted Transformers	**41.6629**	**2.8489**

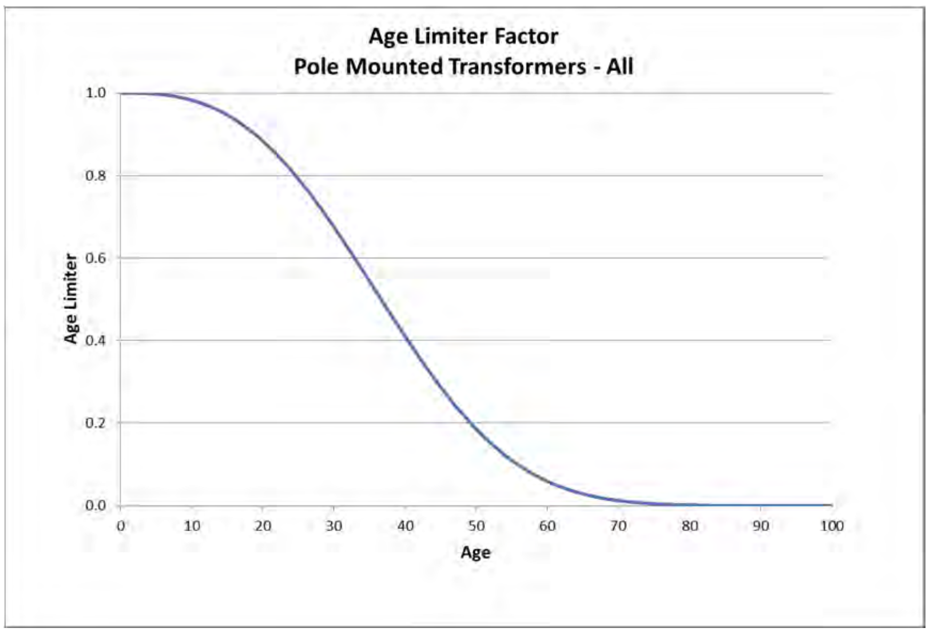

Figure 4-1 Age Limiting Factor Criteria - - Pole-Mounted Transformers

4.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 87% of the population. The average age was found to be 25 years.

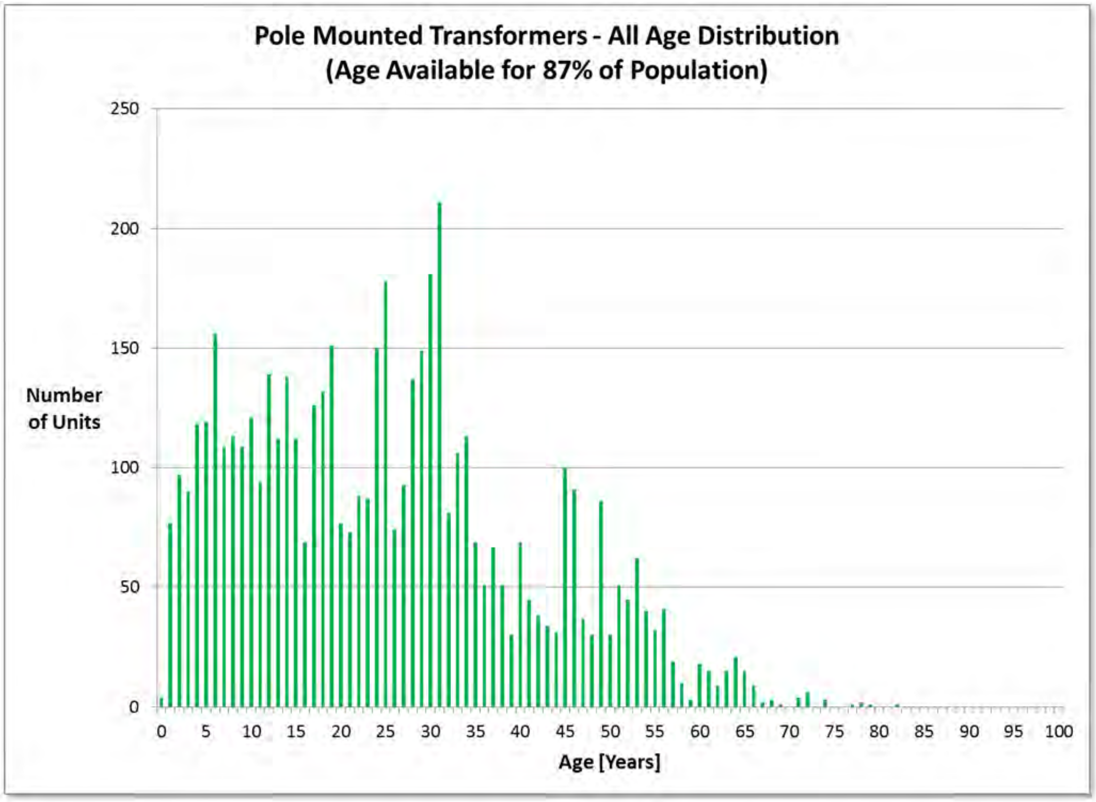

Figure 4-2 Age Distribution - Pole-Mounted Transformers

4.3 Health Index Results

At the time of assessment, there were 6077 in service Pole-Mounted Transformers at NPEI. There were 6051 units with sufficient data for assessment.

The average Health Index for this asset group is 74%. Approximately 20% of the units were found to be in very poor to poor condition.

The Health Index Results are as follows:

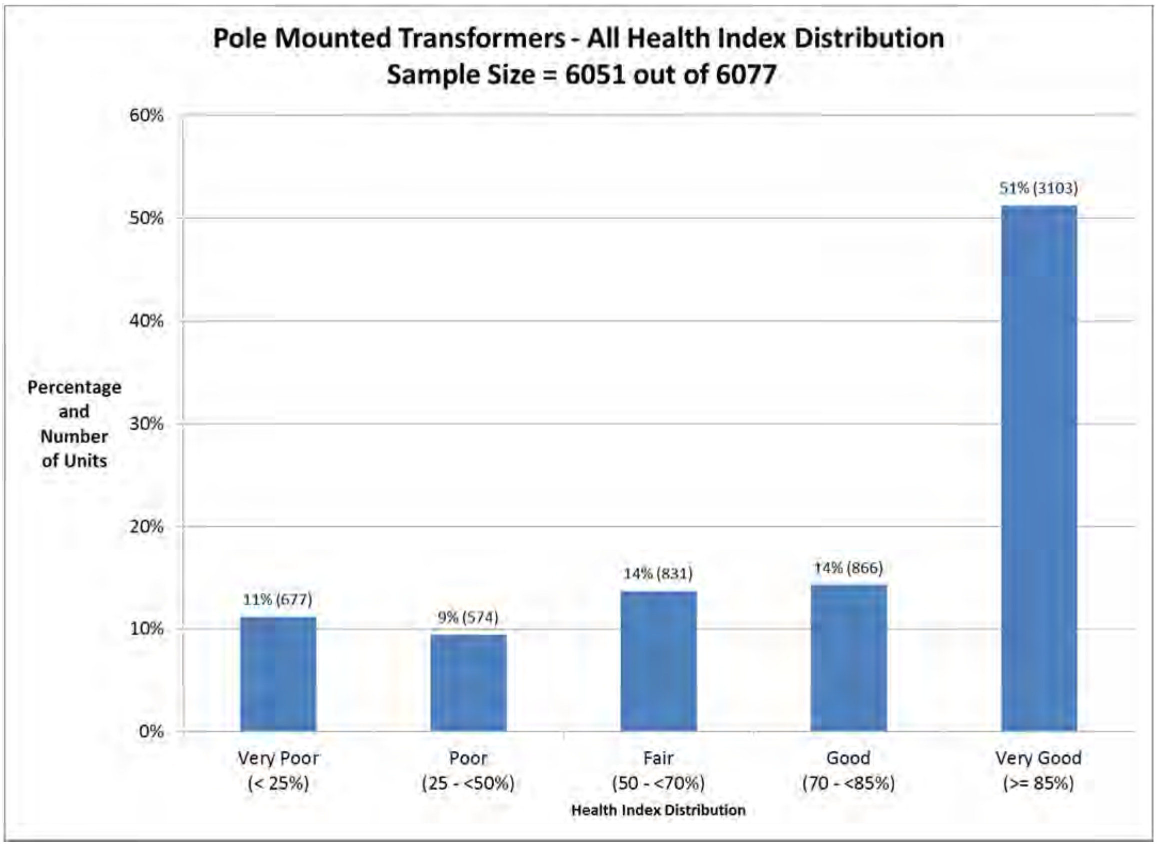

Figure 4-3 Health Index Distribution - Pole-Mounted Transformers

4.4 Condition-Based Flagged for Action Plan

As it is assumed that Pole-Mounted Transformers are reactively addressed, the Flagged for Action Plan is based on the asset failure rate, f(t).

The Flagged for Action Plan is based on the expected number of units that require action in a given year. As it may not always be feasible to address assets as per the optimal plan, a "levelized" plan, based on accelerating action prior to expected time of action, is also given.

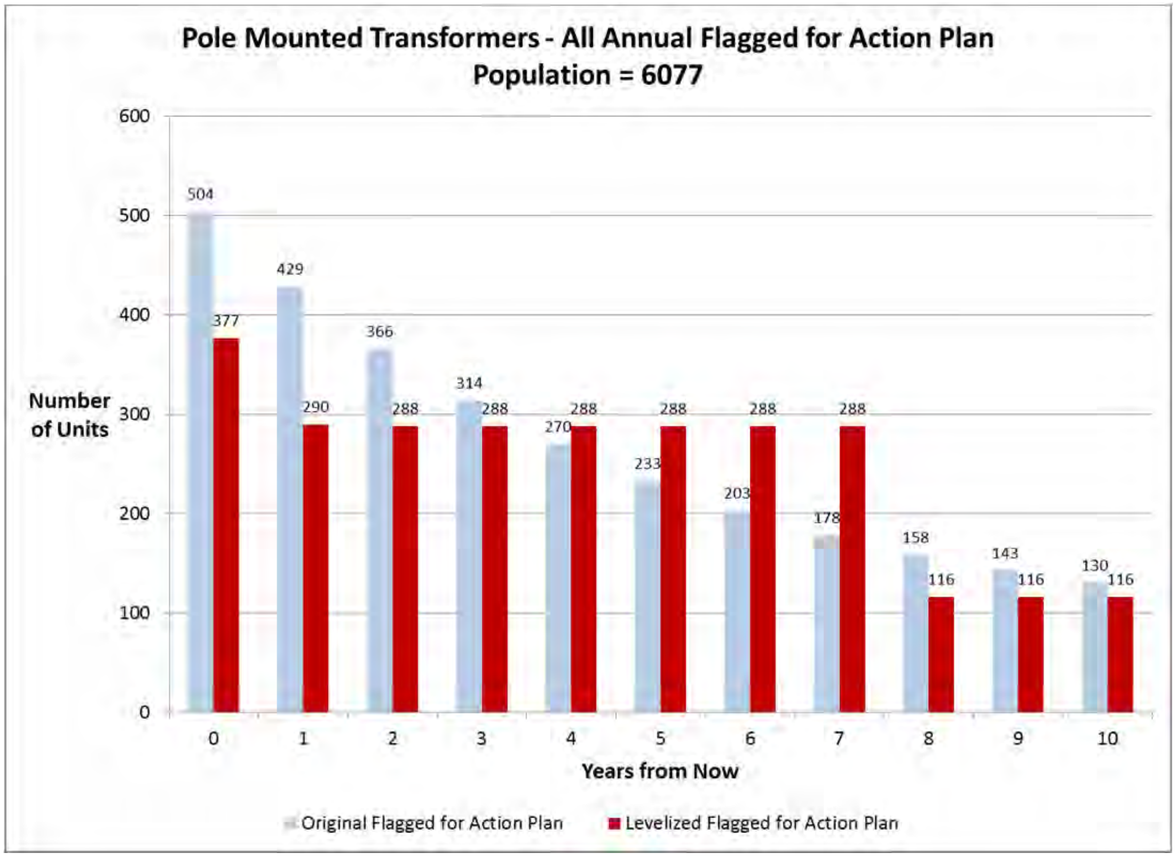

Figure 4-4 Flagged for Action Plan - Pole-Mounted Transformers

4.5 Data Analysis

Age and loading were the only data available for Pole-Mounted Transformers. Although inspections are regularly conducted, results of inspections have yet to be linked to the inventory database so as to be incorporated into the Health Indexing process.

4.5.1 Data Gap

The following data gaps have been identified:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Tank Corrosion	Physical Condition	☆☆☆	Transformer oil tank	Tank surface rust or deterioration due to environmental factors	Visual inspection
Oil Leak	Connection & Insulation	☆☆☆	Transformer tank	Leakage	Visual inspection
Connection		☆☆	Transformer connection	Poor connection	Visual inspection
Grounding		☆	Transformer tank	Poor grounding wire connection	Visual inspection
Bushing		☆☆	Bushing	Crack / Dirt	Visual inspection
Overall	Service Record	☆☆☆	Transformer	General status evaluation based on routine operation and inspection	Visual inspection

4.5.2 Data Availability Distribution

As a majority of units had age and loading, the average DAI for Pole-Mounted Transformers, as measured against the existing data set, is 96%.

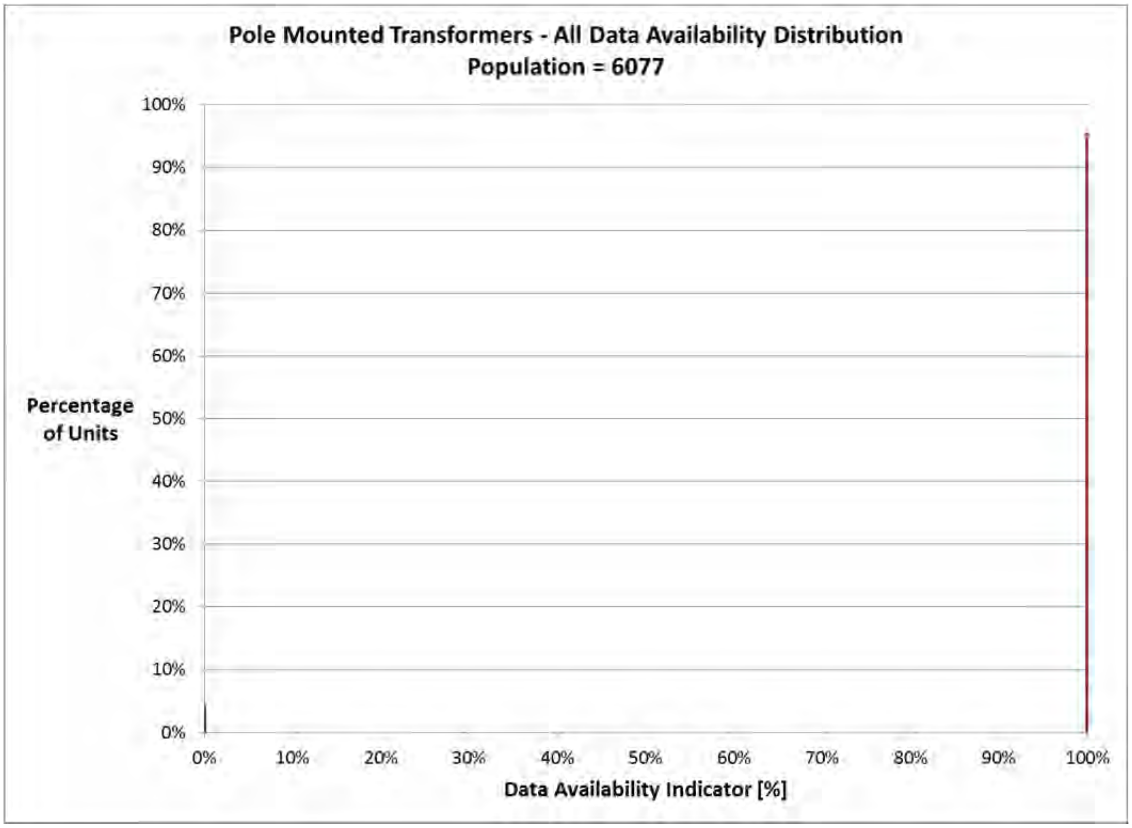

Figure 4-5 Data Availability Distribution - Pole-Mounted Transformers

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5 Poles – NPEI-owned

5.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Poles – NPEI-owned. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

5.1.1 Condition and Sub-Condition Parameters

Table 5-1 Condition Parameters and Weights - Poles – NPEI-owned

Condition Parameter			**Sub-Condition Parameter**			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Pole Strength	7	1	Pole Strength	1	Table 5-2
2	Accessories	3	1	Guy	2	Table 5-2
			2	Grounding	1	Table 5-2
			3	Anchor	1	Table 5-2
			4	Crossarm	3	Table 5-2
3	Service Record	6	1	Overall	1	Table 5-2
	Age Limiter Factor				Figure 5-1	

5.1.2 Condition Parameter Criteria

Inspections

Table 5-2 Inspection Score - Poles – NPEI-owned

CPF	Overall	Strength	Crossarm	Guy	Anchor	Grounding
0		0	Crooked /Damaged	Damaged	Pulled out	Damaged / Removed
1	Poor	1-2	Loose / Rotting	Frayed / Loose / Rubbing		Connection issue /Exposed / Rod Above Grade
2	Fair	3-4	Other	Other	Other	Other
3		5	OK	OK	OK	OK
4	Good	>5				

Age Limiting Factor

In this project, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. Principle of applying the degradation survival curve is described in section II.2.1.

In this project, the parameters of Poles – NPEI-owned age limiting curve are shown in the following table. All of them were based on generic industry practice.

Table 5-3 Age Limiting Curve Parameters - Poles – NPEI-owned

Asset Type	α	β
Poles – Wood	**65.5929**	**5.5258**
Poles - Concrete	**70.8448**	**9.0278**
Poles - Steel	**70.8448**	**9.0278**

Figure 5-1 Age Limiting Factor Criteria - - Poles – NPEI-owned

5.2 Age Distribution

The age distribution is shown in the figures below.

--- Wood poles

Age was available for 98% of the population. The average age was found to be 33 years.

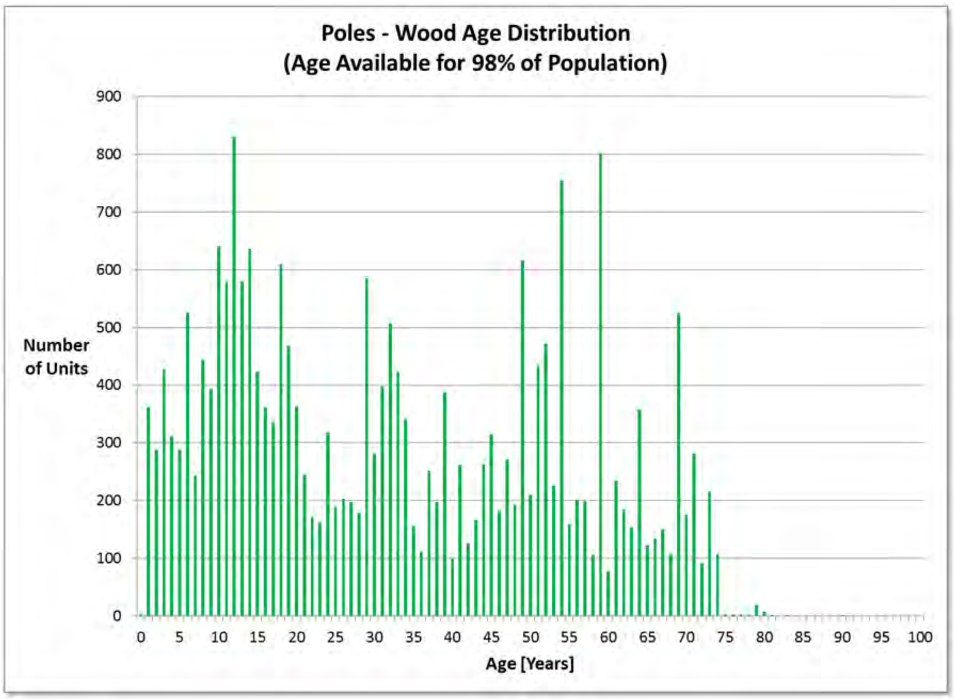

Figure 5-2 Age Distribution - Poles – NPEI-owned (Wood Type)

--- Concrete poles

Age was available for 98% of the population. The average age was found to be 29 years.

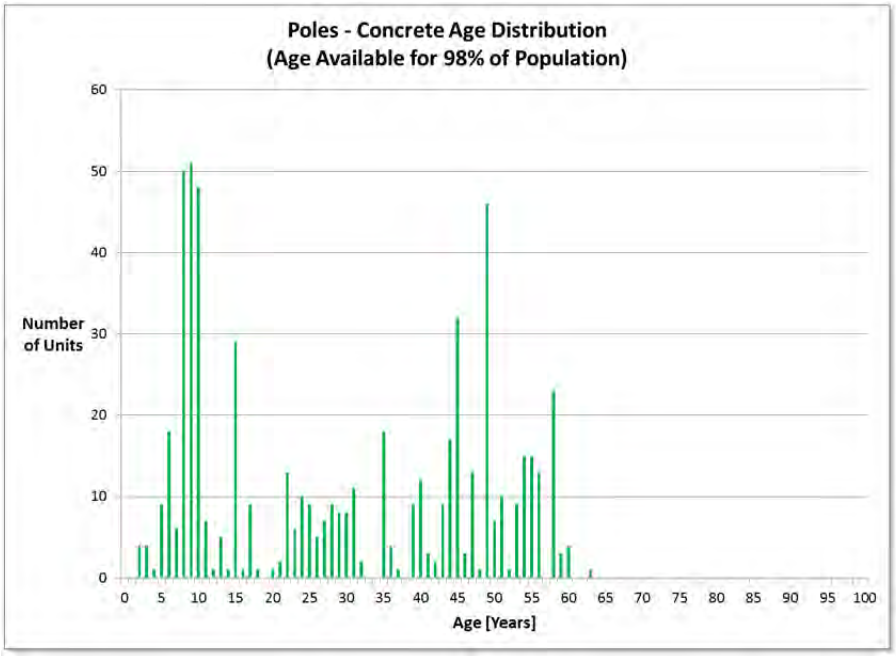

Figure 5-3 Age Distribution - Poles – NPEI-owned (Concrete Type)

---Steel poles

Age was available for 100% of the population. The average age was found to be 20 years.

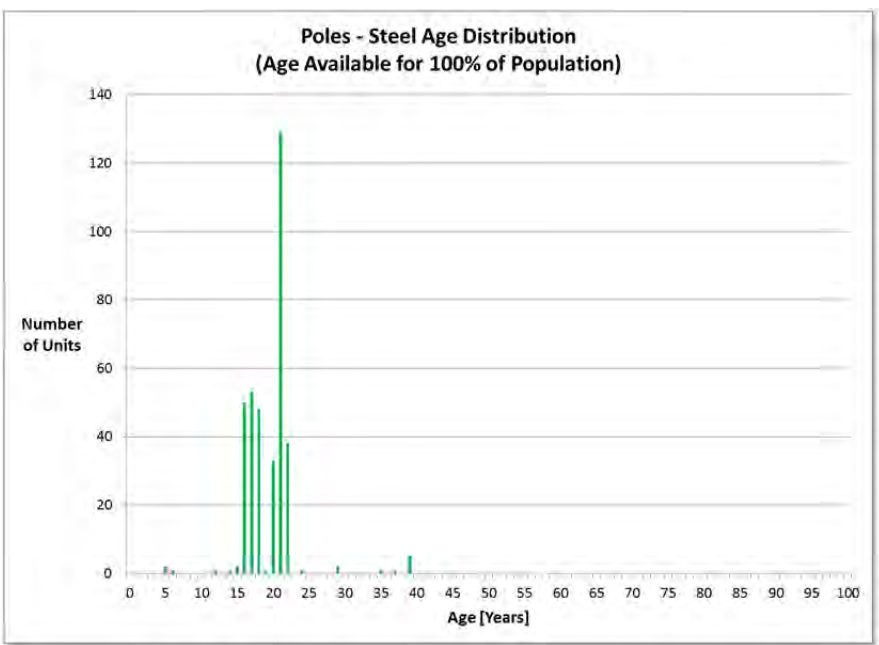

Figure 5-4 Age Distribution - Poles – NPEI-owned (Steel Type)

5.3 Health Index Results

The Health Index Results are shown in the following diagrams:

--- Wood poles

At the time of assessment, there were 23830 in service Poles – NPEI-owned (wood type) at NPEI. There were 23733 units with sufficient data for assessment.

The average Health Index for this asset group is 81%. Approximately 12% of the units were found to be in very poor to poor condition.

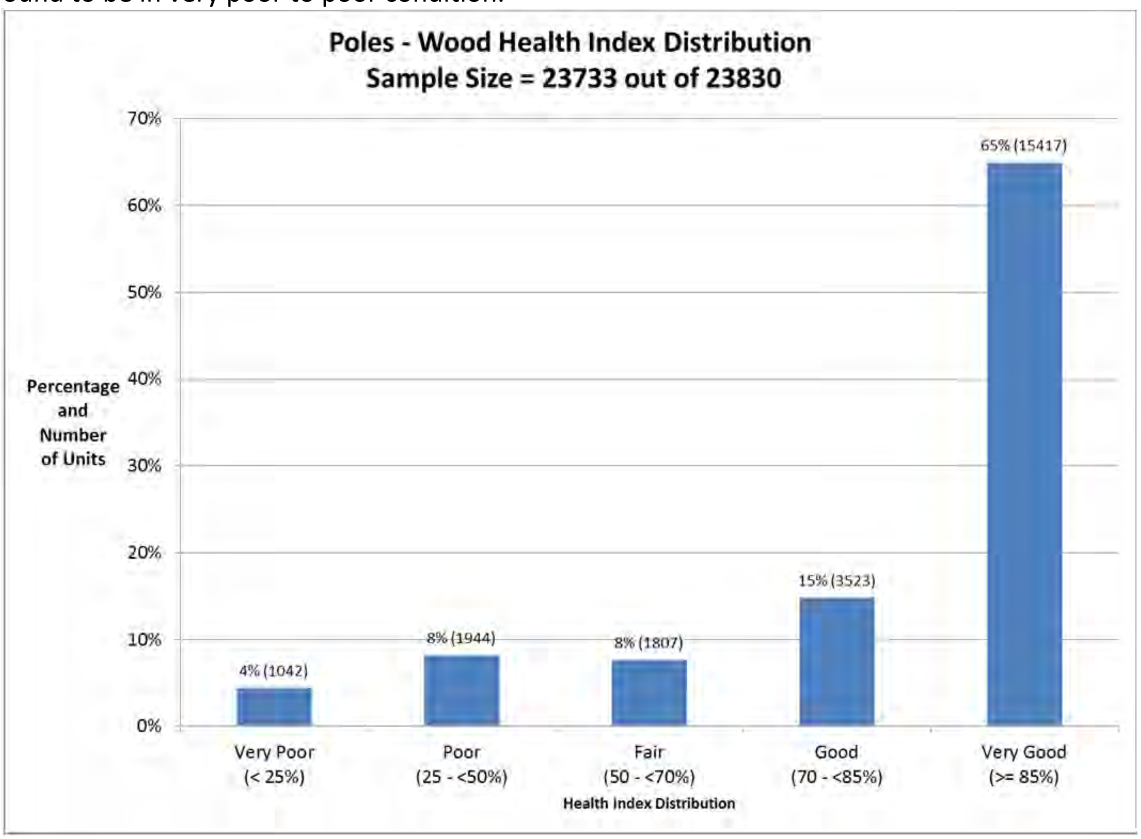

Figure 5-5 Health Index Distribution - Poles – NPEI-owned (Wood Type)

--- Concrete poles

At the time of assessment, there were 621 in service Poles – NPEI-owned (concrete type) at NPEI. There were 618 units with sufficient data for assessment.

The average Health Index for this asset group is 91%. Approximately 2% of the units were found to be in very poor to poor condition.

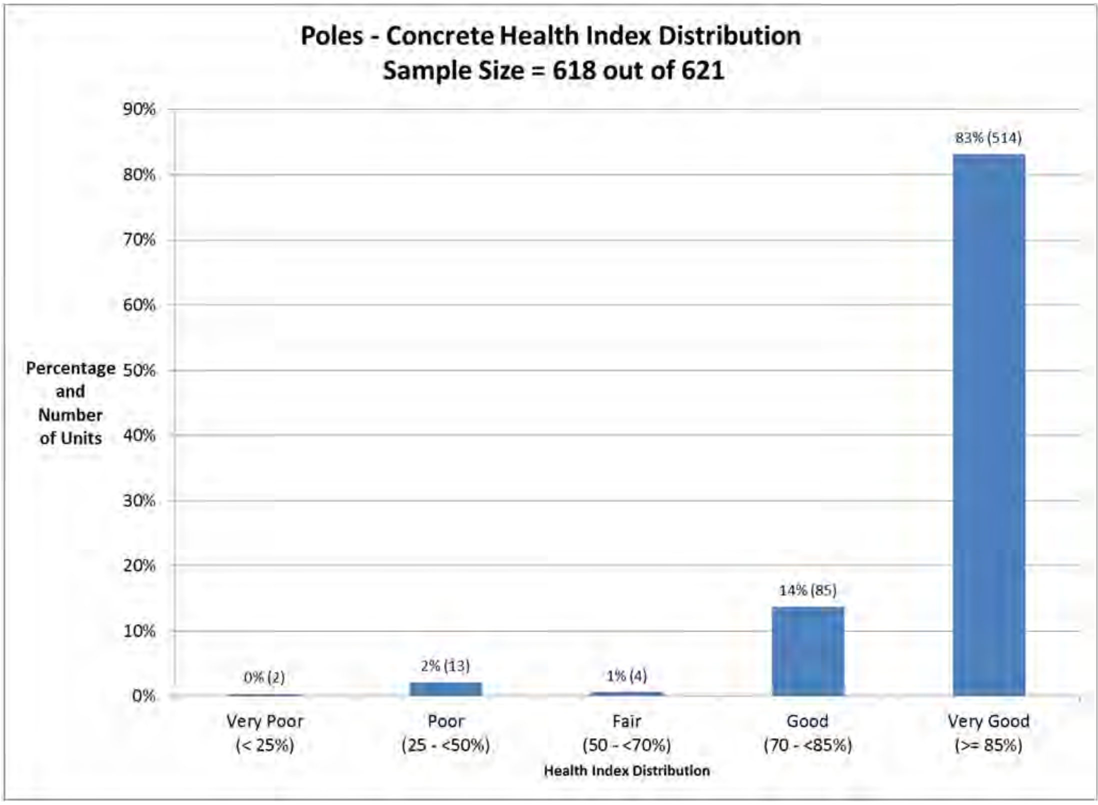

Figure 5-6 Health Index Distribution - Poles – NPEI-owned (Concrete Type)

--- Steel poles

At the time of assessment, there were 371 in service Poles – NPEI-owned (steel type) at NPEI. There were 370 units with sufficient data for assessment.

The average Health Index for this asset group is 95%. None of the units were found to be in very poor to poor condition.

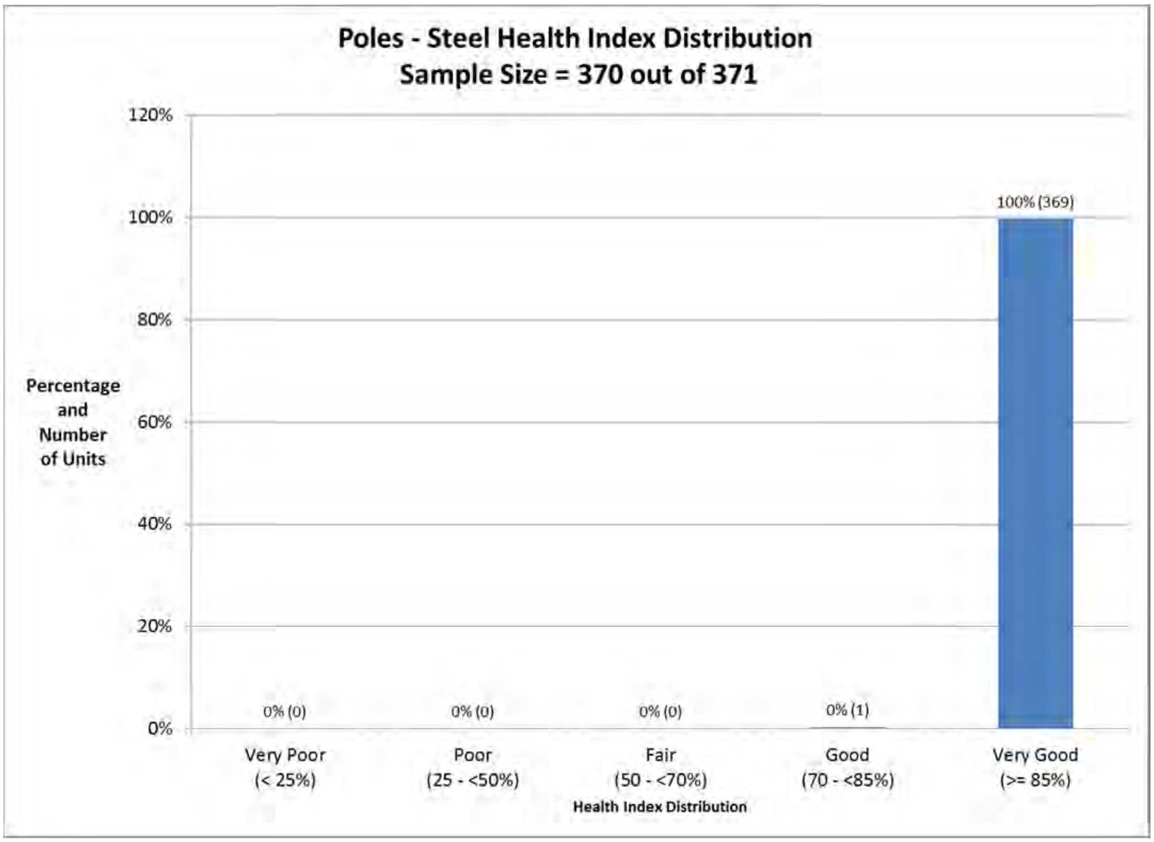

Figure 5-7 Health Index Distribution - Poles – NPEI-owned (Steel Type)

5.4 Condition-Based Flagged for Action Plan

While Poles – NPEI-owned are both proactively and reactively addressed, the Flagged for Action Plan is based on the asset failure rate, f(t).

The Flagged for Action Plan is based on the expected number of units that require action in a given year. In case it is not always be feasible to address assets as per the optimal plan, a "levelized" plan, based on accelerating action prior to expected time of action, will be given.

--- Wood poles

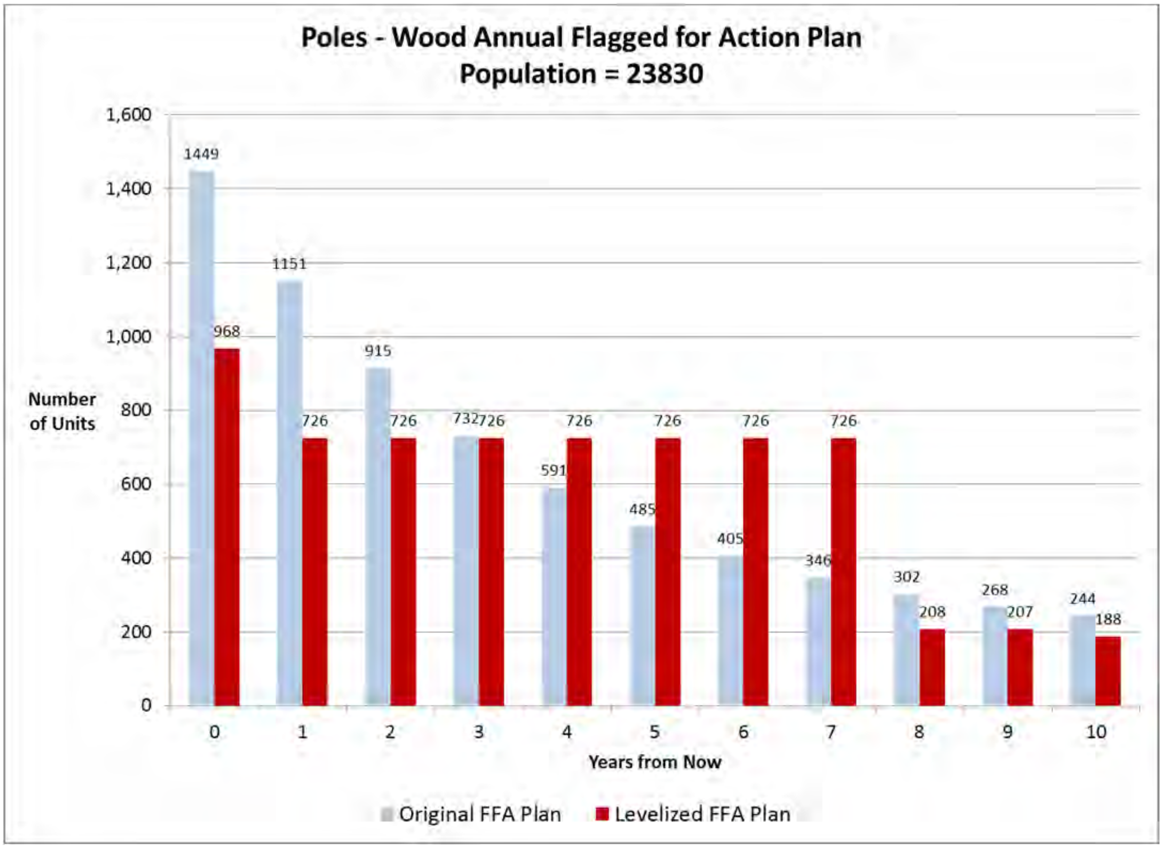

Figure 5-8 Flagged for Action Plan Poles – NPEI-owned (Wood Type)

--- Concrete poles

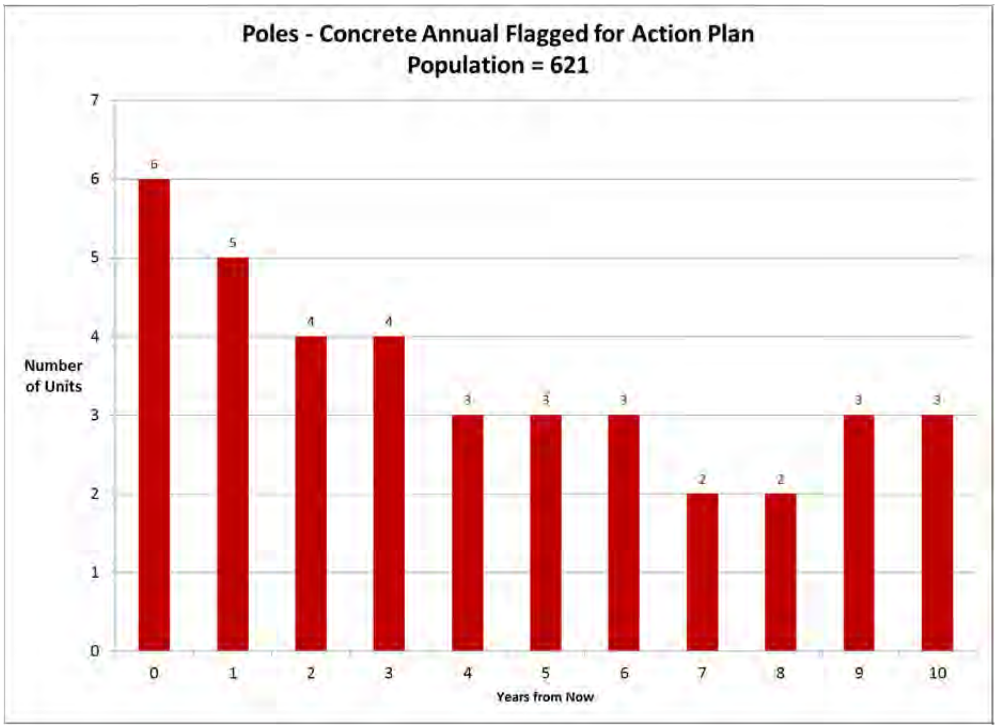

Figure 5-9 Flagged for Action Plan - Poles – NPEI-owned (Concrete Type)

--- Steel poles

No asset unit in this category is flagged for action.

5.5 Data Analysis

The data available for Poles – NPEI-owned includes age and inspection data related to physical condition.

5.5.1 Data Gaps

The only other data recommended is pole physical condition.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Top	Pole Condition	☆	Pole	Top feathering	On-site inspection
Rot		☆		Surface decay	
Pocket		☆ ☆		Internal decay	
Damage		☆		Physical damage	

5.5.2 Data Availability Distribution

A majority of the population had age and inspections. The average DAI for Poles – NPEI-owned, as measured against the existing data set, are 92%, for steel type respectively.

--- Wood poles

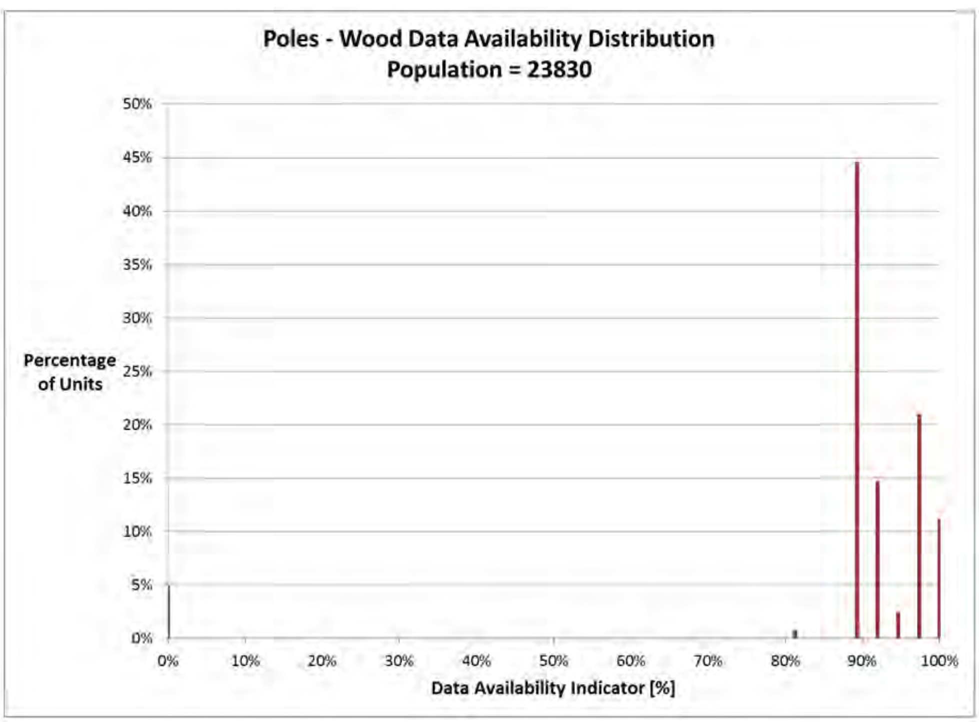

Figure 5-10 Data Availability Distribution - Poles – NPEI-owned (Wood Type)

--- Concrete poles

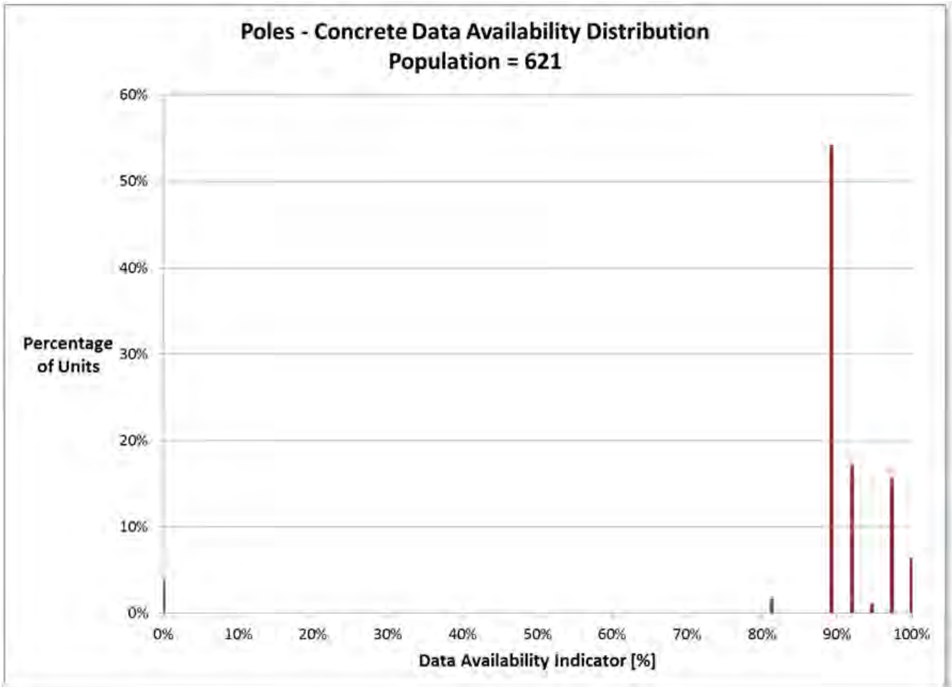

Figure 5-11 Data Availability Distribution - Poles – NPEI-owned (Concrete Type)

--- Steel poles

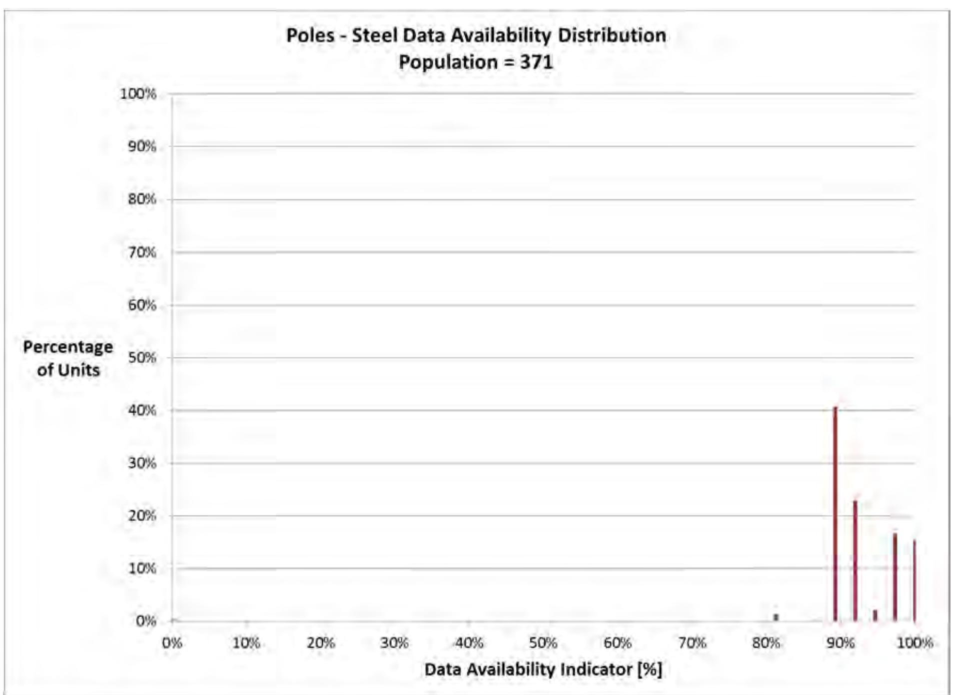

Figure 5-12 Data Availability Distribution - Poles – NPEI-owned (Steel Type)

6 Poles – Non NPEI-owned

6.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Poles – Non NPEI-owned. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

6.1.1 Condition and Sub-Condition Parameters

Table 6-1 Condition Parameters and Weights - Poles – Non NPEI-owned

Condition Parameter			Sub-Condition Parameter			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Pole Strength	7	1	Pole Strength	1	Table 6-2
2	Accessories	3	1	Guy	2	Table 6-2
			2	Grounding	1	Table 6-2
			3	Anchor	1	Table 6-2
			4	Crossarm	3	Table 6-2
3	Service Record	6	1	Overall	1	Table 6-2
	Age Limiter Factor				Figure 6-1	

6.1.2 Condition Parameter Criteria

Inspections

Table 6-2 Inspection Score Poles – Non NPEI-owned

CPF	Overall	Strength	Crossarm	Guy	Anchor	Grounding
0		0	Crooked /Damaged	Damaged	Pulled out	Damaged / Removed
1	Poor	1-2	Loose / Rotting	Frayed / Loose / Rubbing		Connection issue /Exposed / Rod Above Grade
2	Fair	3-4	Other	Other	Other	Other
3		5	OK	OK	OK	OK
4	Good	>5				

Age Limiting Factor

In this project, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. Principle of applying the degradation survival curve is described in section II.2.1.

In this project, the parameters of Poles – Non NPEI-owned age limiting curve are shown in the following table. All of them were based on generic industry practice.

Table 6-3 Age Limiting Curve Parameters - Poles – Non NPEI-owned

Asset Type	α	β
Poles – Wood	**65.5929**	**5.5258**
Poles - Concrete	**70.8448**	**9.0278**
Poles - Steel	**70.8448**	**9.0278**

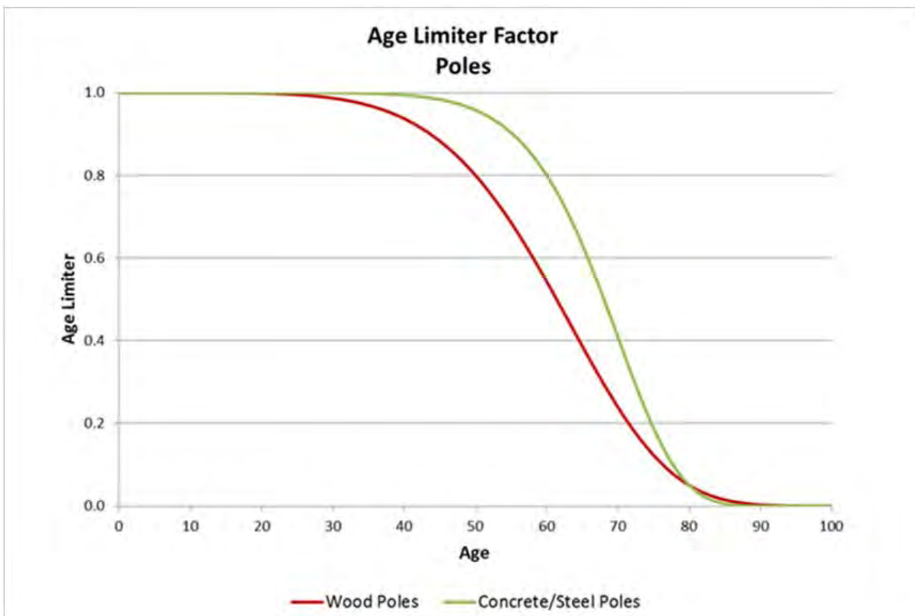

Figure 6-1 Age Limiting Factor Criteria - - Poles – Non NPEI-owned

6.2 Age Distribution

The age distribution is shown in the figures below.

--- Wood poles

Age was available for 25% of the population. The average age was found to be 13 years.

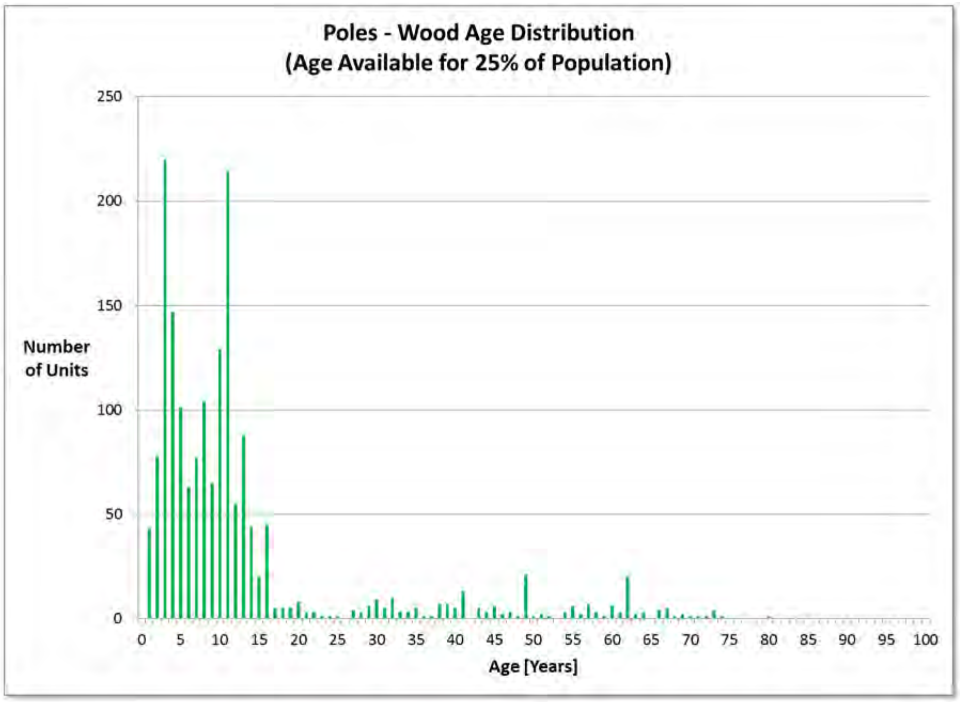

Figure 6-2 Age Distribution - Poles – Non NPEI-owned (Wood Type)

--- Concrete poles

Age was available for 35% of the population. The average age was found to be 8 years.

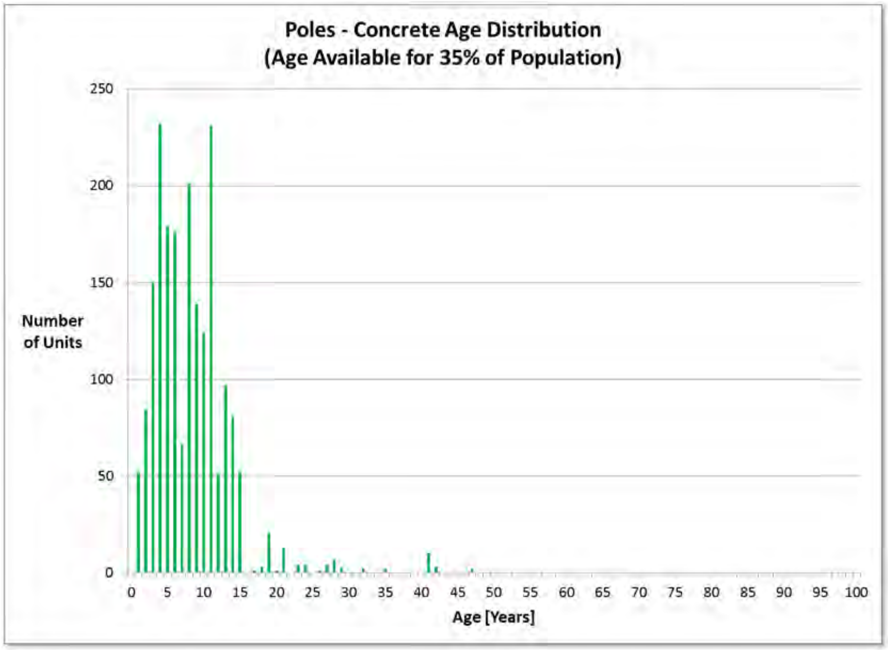

Figure 6-3 Age Distribution Poles – Non NPEI-owned (Concrete Type)

---Steel poles

Age was available for 52% of the population. The average age was found to be 7 years.

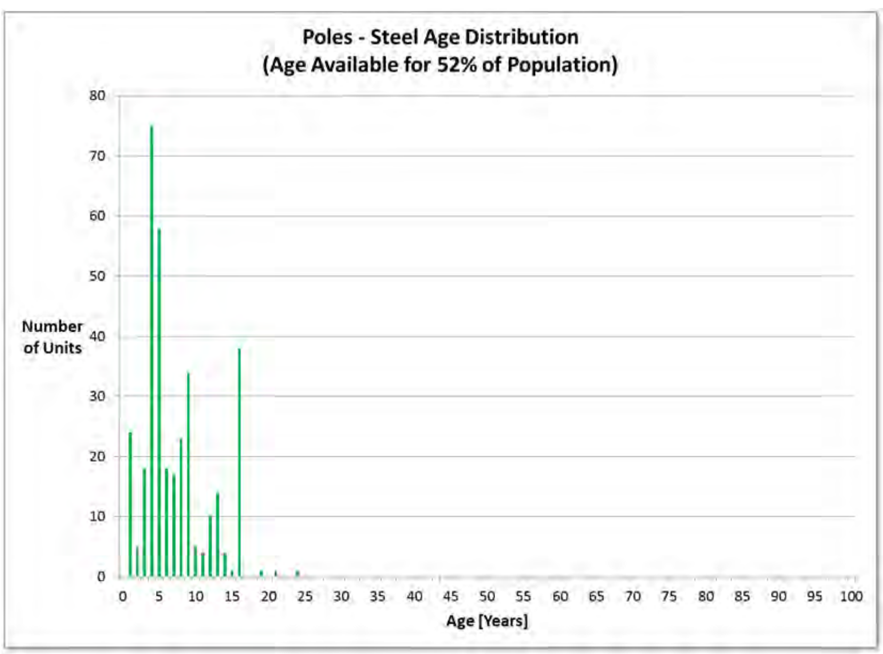

Figure 6-4 Age Distribution Poles – Non NPEI-owned (Steel Type)

6.3 Health Index Results

The Health Index Results are shown in the following diagrams:

--- Wood poles

At the time of assessment, there were 7053 in service Poles – Non NPEI-owned (wood type) at NPEI. There were 6841 units with sufficient data for assessment.

The average Health Index for this asset group is 91%. Approximately 3% of the units were found to be in very poor to poor condition.

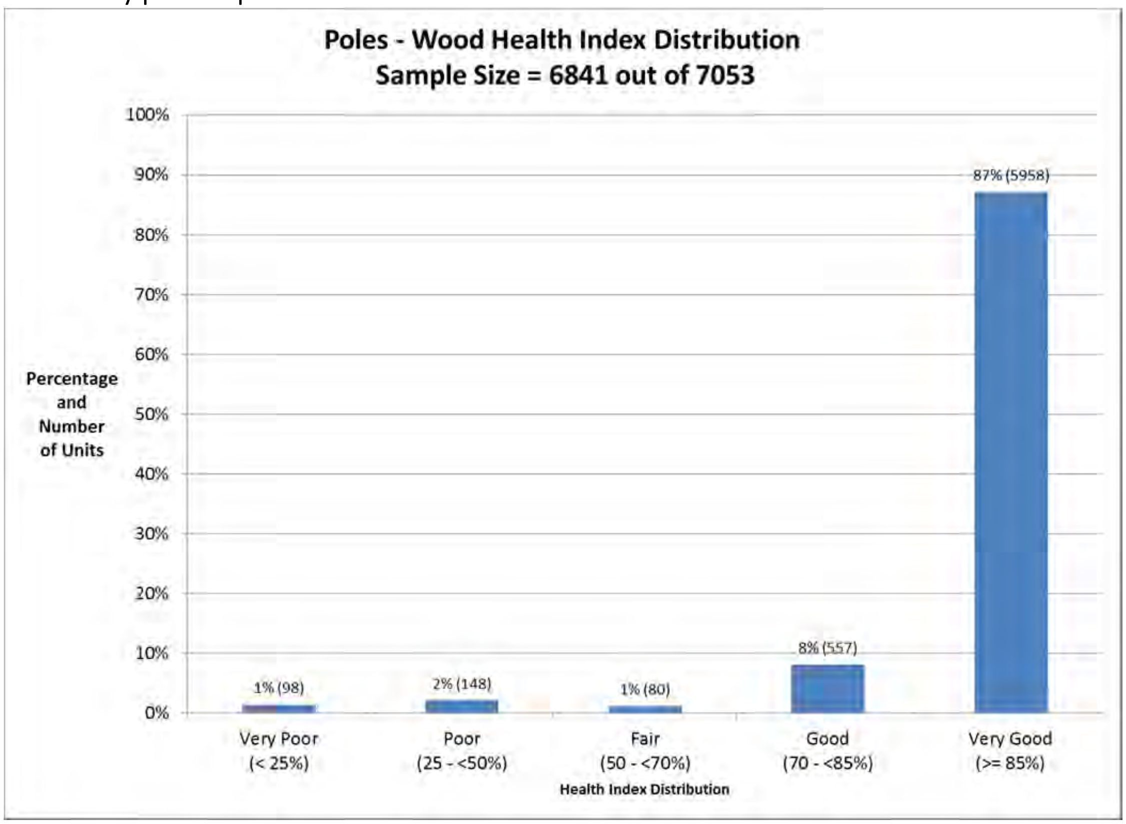

Figure 6-5 Health Index Distribution Poles – Non NPEI-owned (Wood Type)

--- Concrete poles

At the time of assessment, there were 5719 in service Poles – Non NPEI-owned (concrete type) at NPEI. There were 5690 units with sufficient data for assessment.

The average Health Index for this asset group is 95%. Less than 1% of the units were found to be in very poor to poor condition.

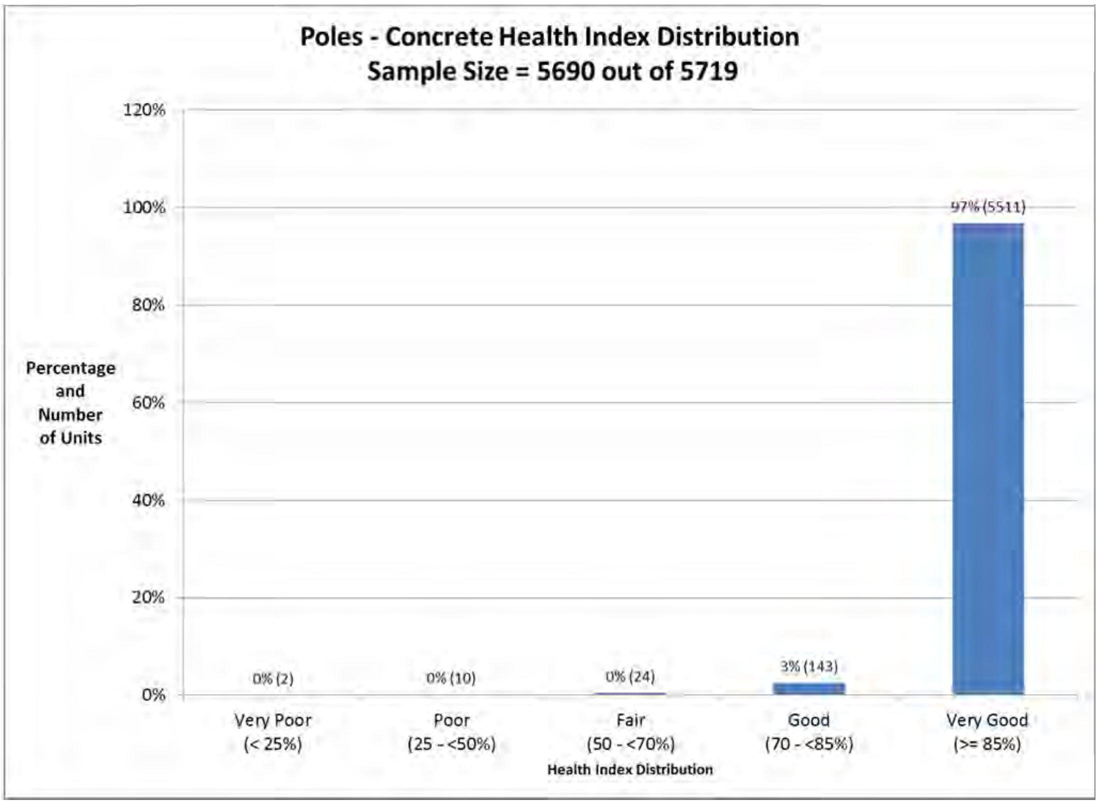

Figure 6-6 Health Index Distribution Poles – Non NPEI-owned (Concrete Type)

--- Steel poles

At the time of assessment, there were 680 in service Poles – Non NPEI-owned (steel type) at NPEI. There were 646 units with sufficient data for assessment.

The average Health Index for this asset group is 96%. None of the units were found to be in very poor to poor condition.

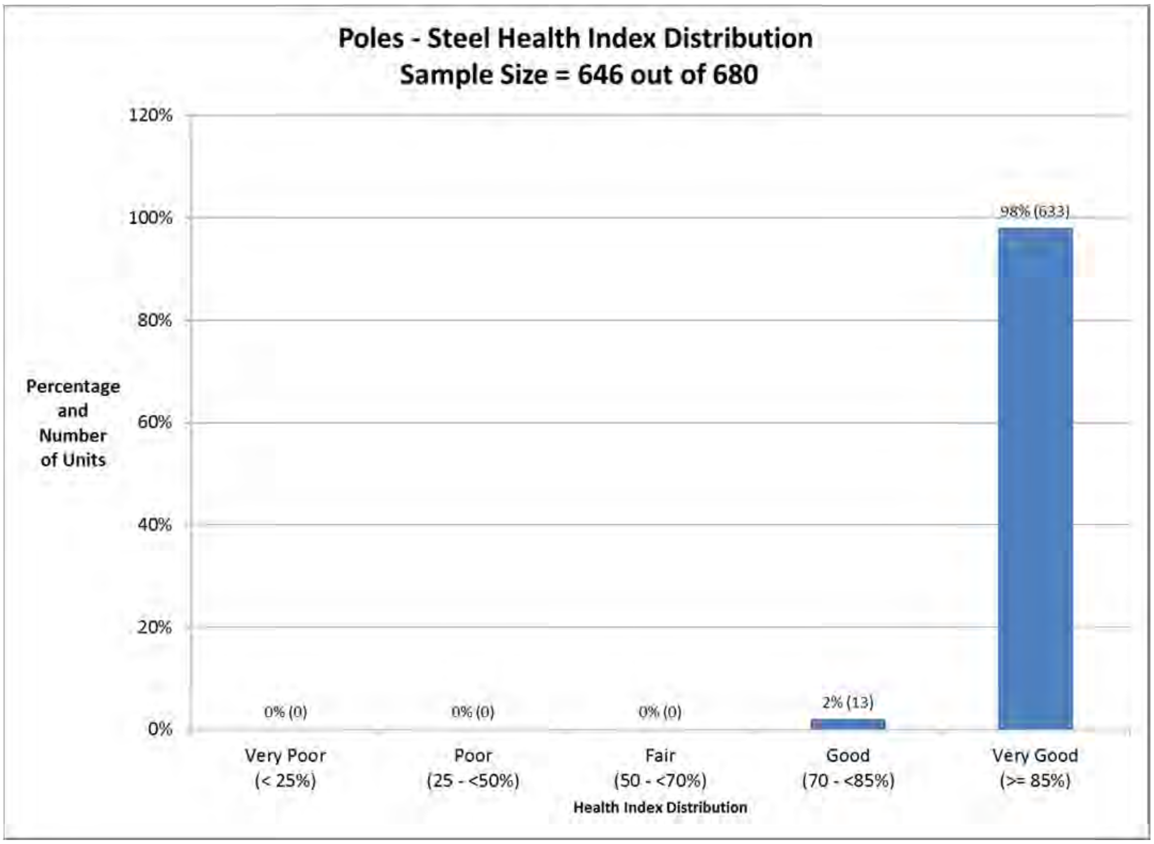

Figure 6-7 Health Index Distribution Poles – Non NPEI-owned (Steel Type)

6.4 Condition-Based Flagged for Action Plan

While Poles – Non NPEI-owned are both proactively and reactively addressed, the Flagged for Action Plan is based on the asset failure rate, f(t).

The Flagged for Action Plan is based on the expected number of units that require action in a given year. In case it is not always be feasible to address assets as per the optimal plan, a "levelized" plan, based on accelerating action prior to expected time of action, will be given.

--- Wood poles

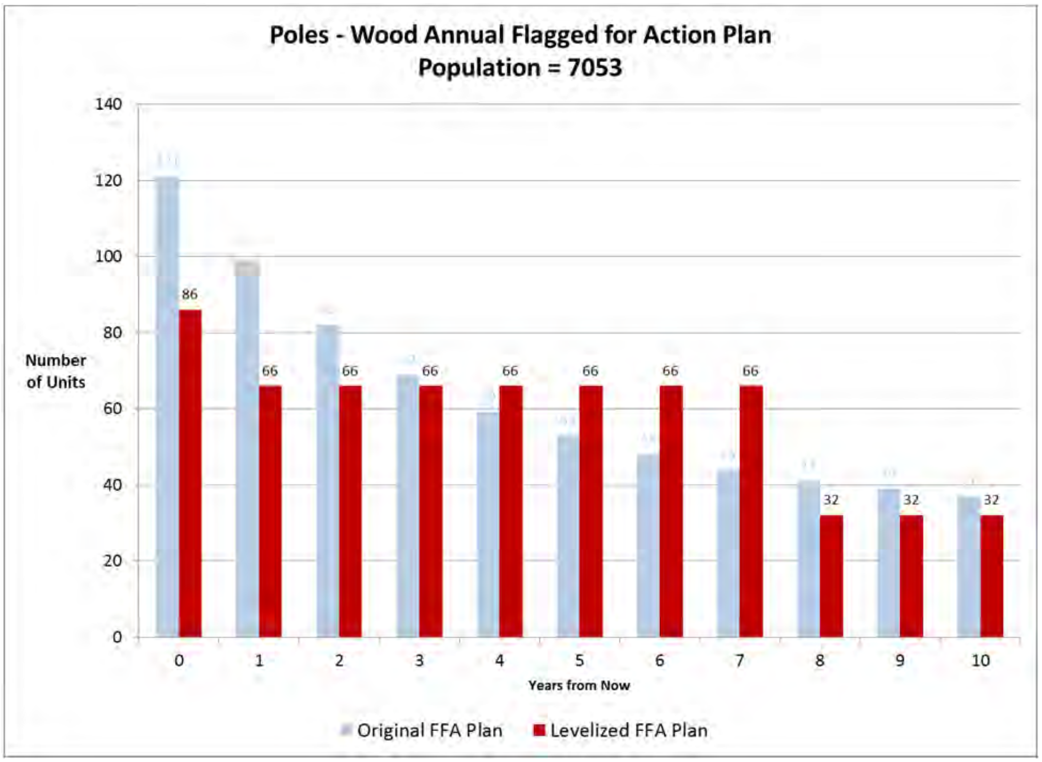

Figure 6-8 Flagged for Action Plan Poles – Non NPEI-owned (Wood Type)

--- Concrete poles

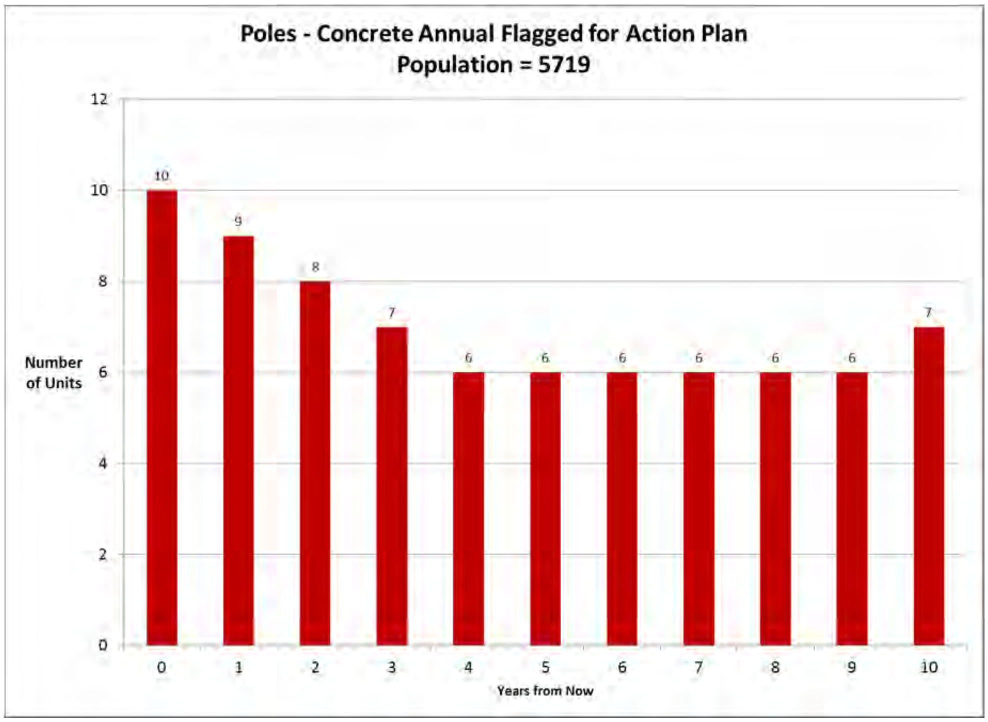

Figure 6-9 Flagged for Action Plan Poles – Non NPEI-owned (Concrete Type)

--- Steel poles

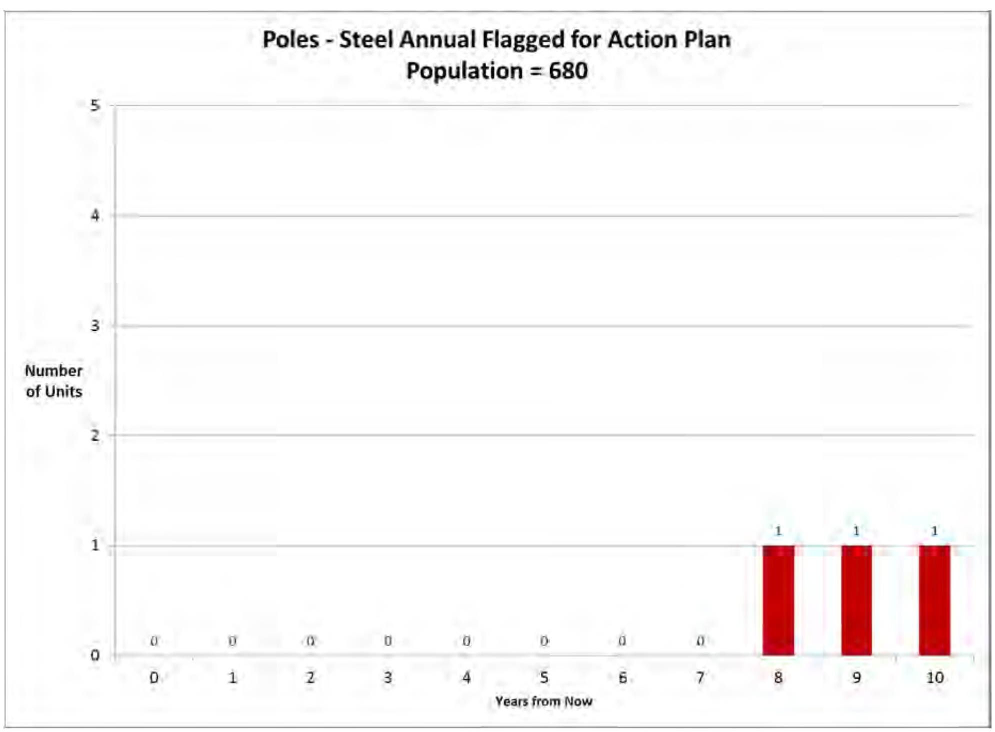

Figure 6-10 Flagged for Action Plan Poles – Non NPEI-owned (Steel Type)

6.5 Data Analysis

The data available for Poles – Non NPEI-owned includes age and inspection data related to physical condition.

6.5.1 Data Gaps

The only other data recommended is pole physical condition.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Top	Pole Condition	☆	Pole	Top feathering	On-site inspection
Rot		☆		Surface decay	
Pocket		☆ ☆		Internal decay	
Damage		☆		Physical damage	

6.5.2 Data Availability Distribution

A majority of the population had age and inspections. The average DAI for Poles – Non NPEI-owned, as measured against the existing data set, are 92%, for steel type respectively.

--- Wood poles

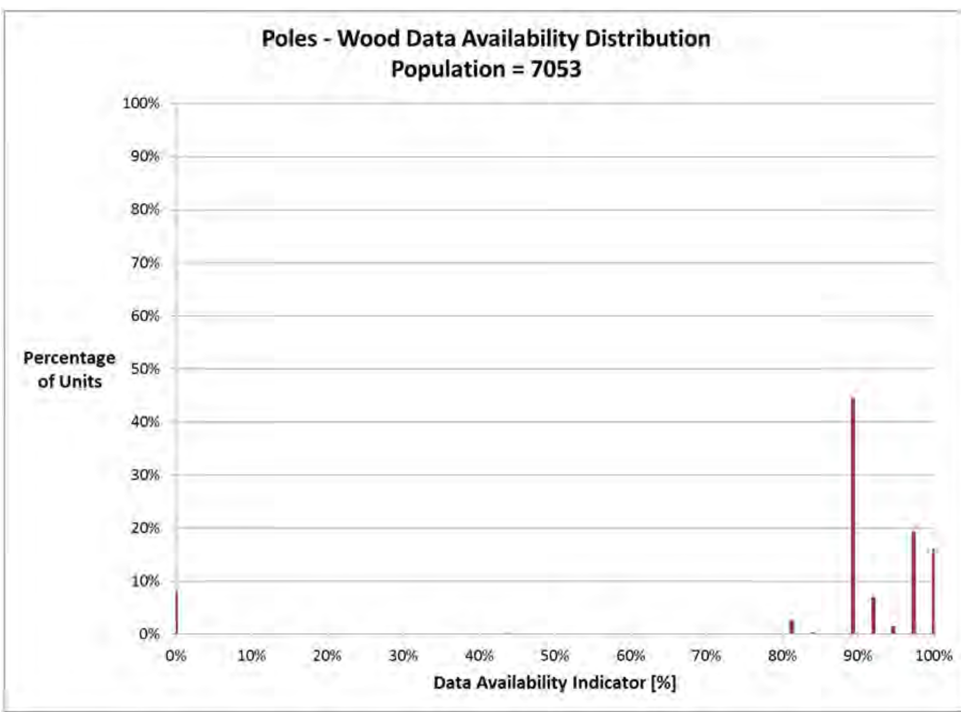

Figure 6-11 Data Availability Distribution Poles – Non NPEI-owned (Wood Type)

--- Concrete poles

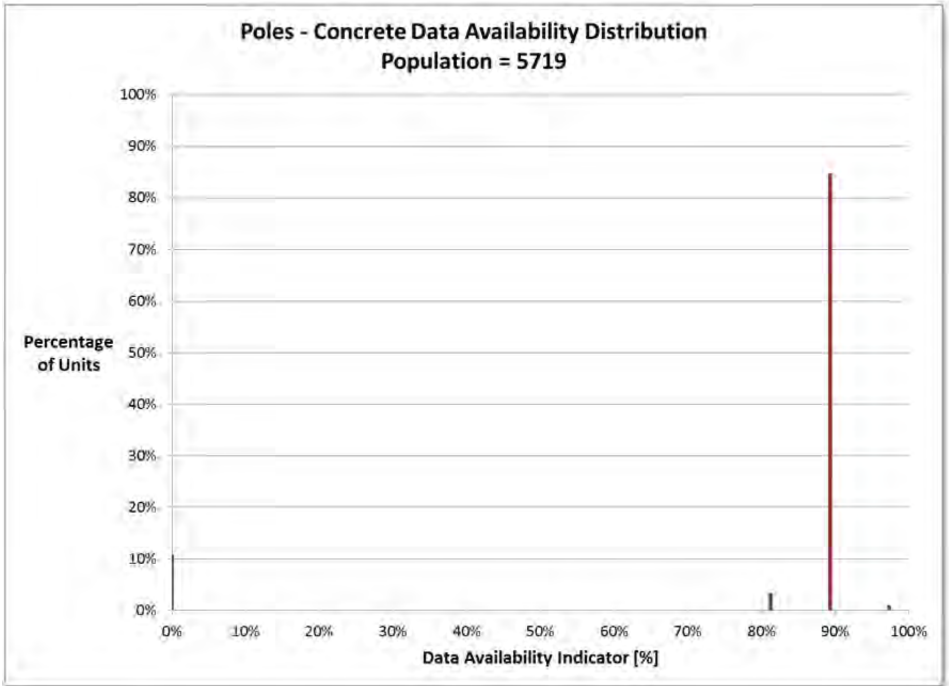

Figure 6-12 Data Availability Distribution Poles – Non NPEI-owned (Concrete Type)

--- Steel poles

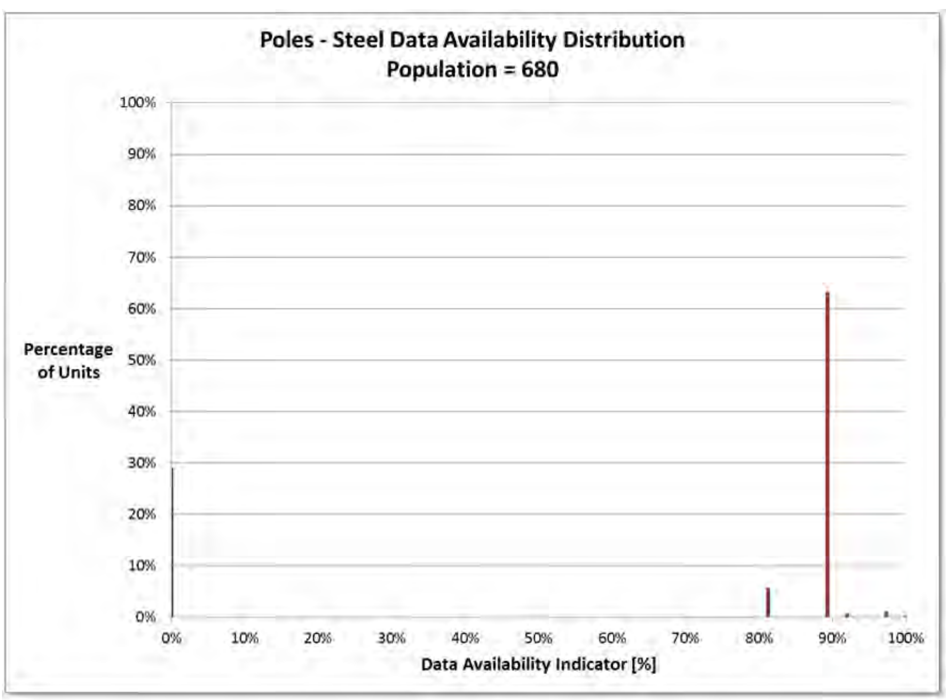

Figure 6-13 Data Availability Distribution Poles – Non NPEI-owned (Steel Type)

7 Pad-Mounted Switchgear

7.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Pad-Mounted Switchgear. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

7.1.1 Condition and Sub-Condition Parameters

Table 7-1 Condition Parameters and Weights - Pad-Mounted Switchgear

Condition Parameter			**Sub-Condition Parameter**			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Physical Condition	3	1	Corrosion	3	Table 7-2
			2	Access	1	Table 7-2
			3	Base	2	Table 7-2
2	Connection and Insulation	5	1	Oil Leak	1	Table 7-2
			2	Grounding	1	Table 7-2
			3	Insulation	1	Table 7-2
3	Service Record	5	1	Action Required	1	Table 7-2
			2	Inspection Result	1	Table 7-2
4	Tests	10	1	IR	1	Table 7-2
			2	Ultrasound	1	Table 7-2

7.1.2 Condition Parameter Criteria

Visual Inspections

Table 7-2 Sample Inspection Condition Criteria - Pad-Mounted Switchgear

CPF	Corrosion	Access	Base	Oil Leak	Insulation	Inspection Results / IR /Ultrasound	Grounding
0	Rusting	Vegetation				Fail	4, 5
1	Graffiti	Fence					3
2		Other			Other		2
3							1
4	Good	Okay	Okay	No/False	Okay	Pass	0

7.2 Age Distribution

Age data is unavailable for Pad-Mounted Switchgear.

7.3 Health Index Results

At the time of assessment, there were 170 in service Pad-Mounted Switchgear at NPEI. There were 61 units with sufficient data for assessment.

The average Health Index for this asset group is 92%. Approximately 2% of the units were found to be in very poor to poor condition.

The Health Index Results are as follows:

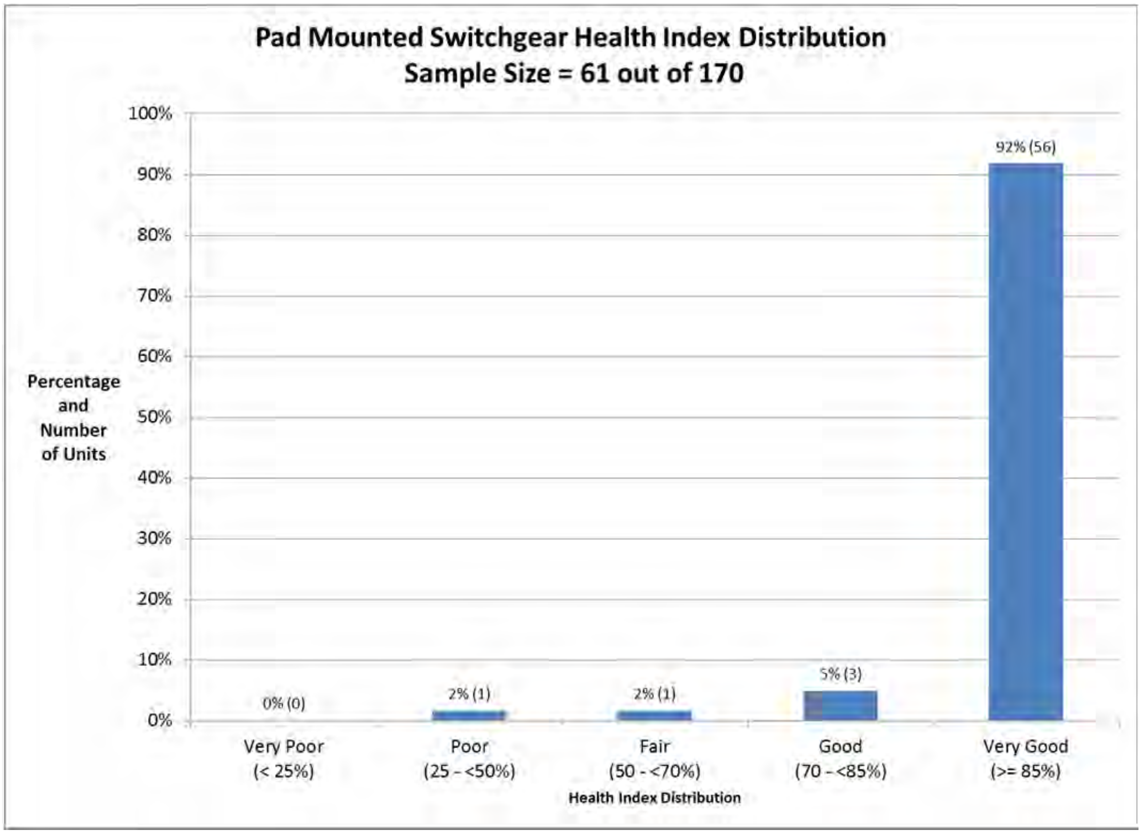

Figure 7-1 Health Index Distribution - Pad-Mounted Switchgear

7.4 Condition-Based Flagged for Action Plan

While Pad-Mounted Switchgear are proactively and reactively addressed, the proactive approach was used in estimating the Flagged for Action Plan. Based on current condition (Health Index) of Pad-Mounted Switchgear and that the assumption that the rate of aging is constant (i.e. units do not continue to degrade faster than what would be typical), the Flagged for Action plan in the next 10 years is shown below.

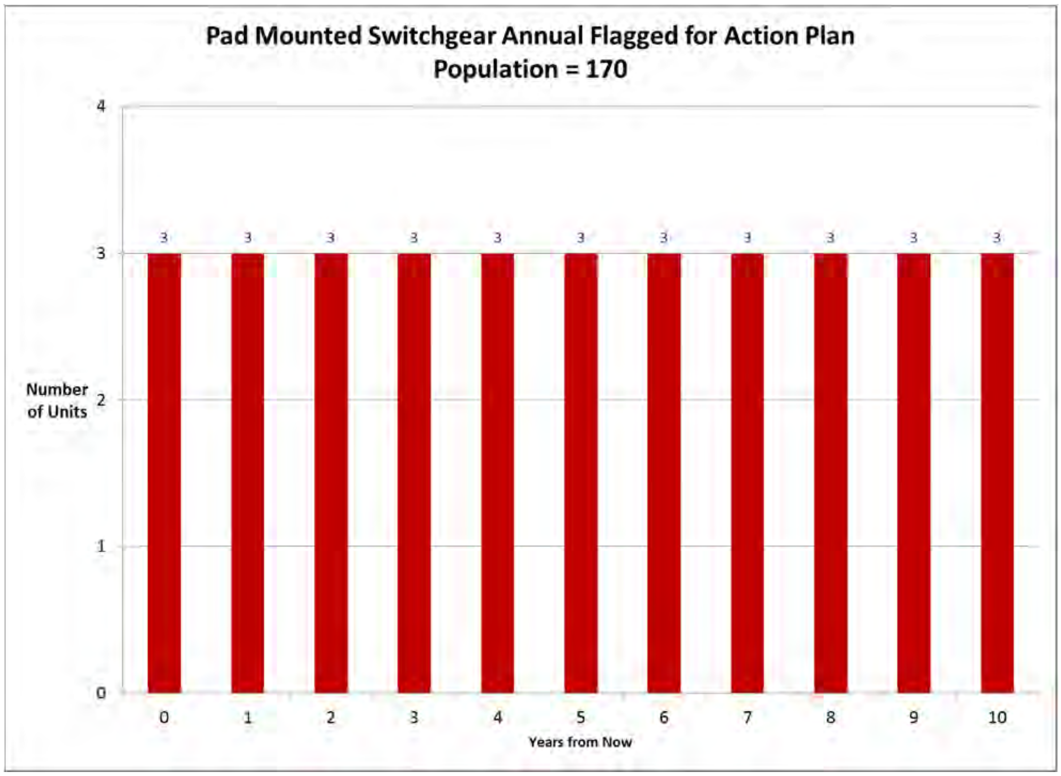

Figure 7-2 Flagged for Action Plan - Pad-Mounted Switchgear

7.5 Data Analysis

The data available for Pad-Mounted Switchgear comes from Inspections and includes condition of enclosure, base, insulation, grounding, and overall switchgear condition. Infrared and ultrasonic tests are also available for this asset group.

7.5.1 Data Gaps

The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Switch	Switch/Fuse Condition	☆☆	Switch	Misalignment, signs of arcing	Visual inspection
Arc Suppressor		☆☆	Switch arc extinction	Arc extinction part surface worn-out	Visual inspection
Fuse		☆☆	Fuse	Fuse visual condition	Visual inspection
Elbows/Inserts		☆☆	Connection	Poor connection / hot spots	Visual inspection or IR scan

7.5.2 Data Availability Distribution

Most of the units had inspection records. As such, the average DAI for Pad-Mounted Switchgear, as measured against the existing data set, is 35%.

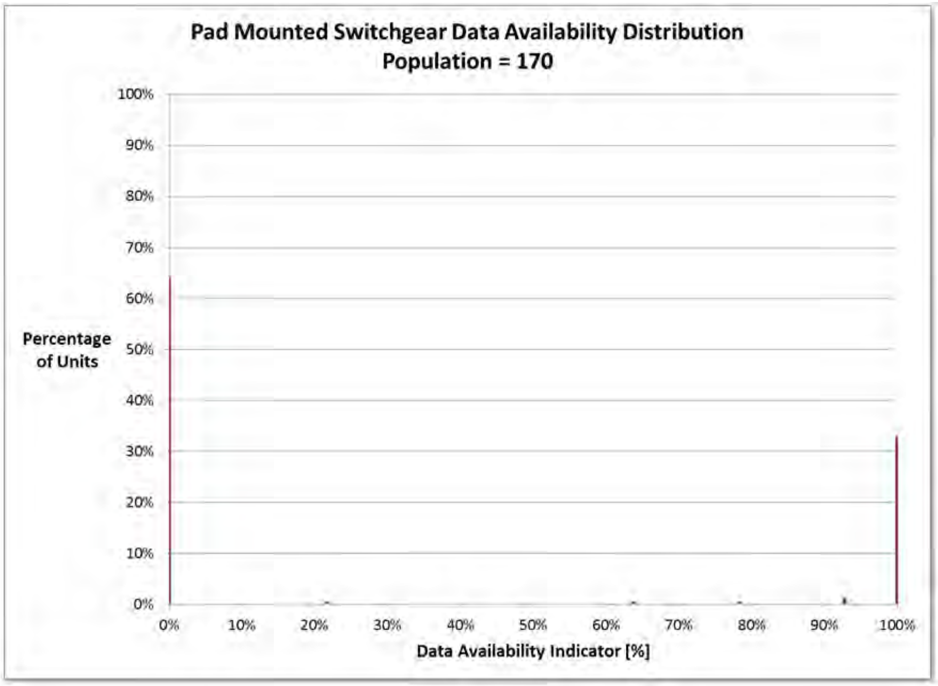

Figure 7-3 Data Availability Distribution - Pad-Mounted Switchgear

8 Underground Cables

8.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Underground Cables. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

8.1.1 Condition and Sub-Condition Parameters

Table 8-1 Condition Parameters and Weights - Underground Cables

Condition Parameter			**Sub-Condition Parameter**			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
	Age Limiter Factor				Figure 8-1	

8.1.2 Condition Parameter Criteria

<u>Age Limiting Factor</u>

In this project, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. Principle of applying the degradation survival curve is described in section II.2.1.

In this project, the parameters of Underground Cables age limiting curve are shown in the following table, based on industry practice.

Table 8-2 Age Limiting Curve Parameters - Underground Cables

Asset Type	α	β
Underground Cables – Direct Buried	**37.9158**	**6.4053**
Underground Cables – In Duct	**53.1336**	**9.0278**

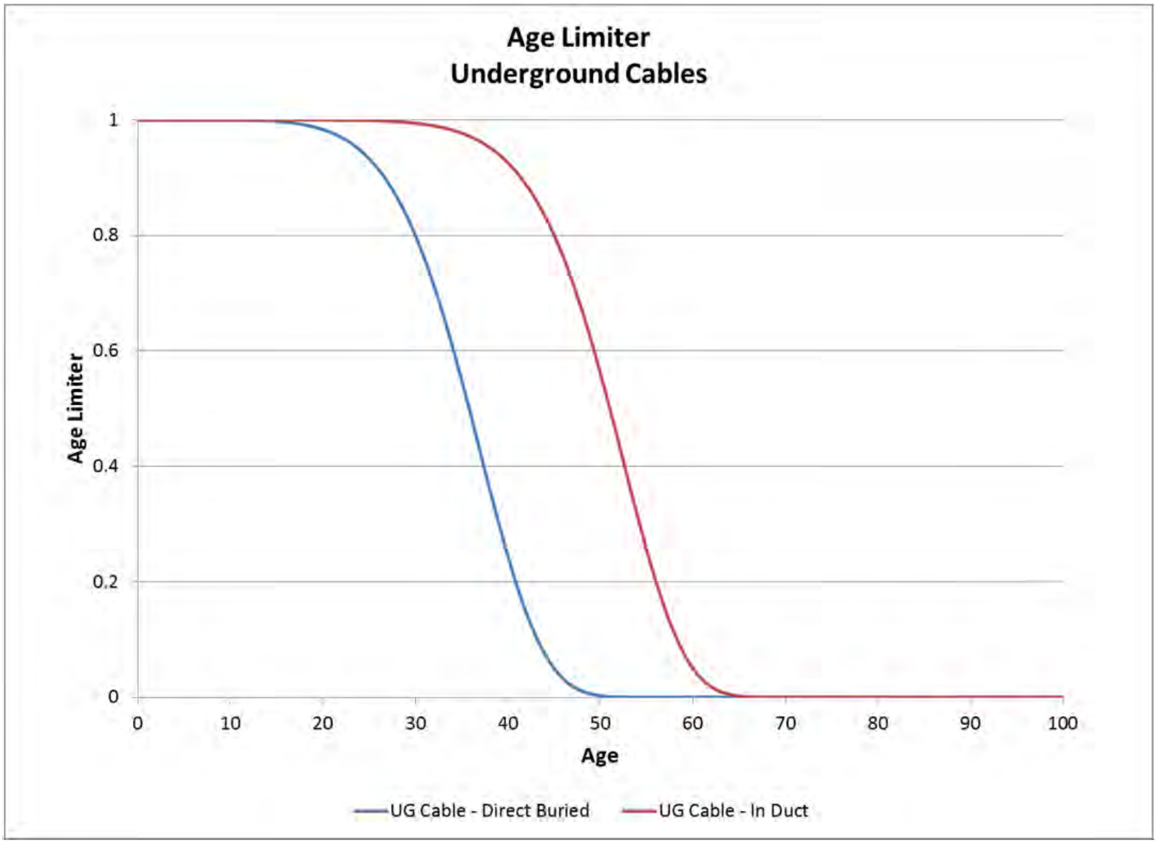

Figure 8-1 Age Limiting Factor Criteria - - Underground Cables

8.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 76% of all cables. The average age was found to be 13 years/conductor-km.

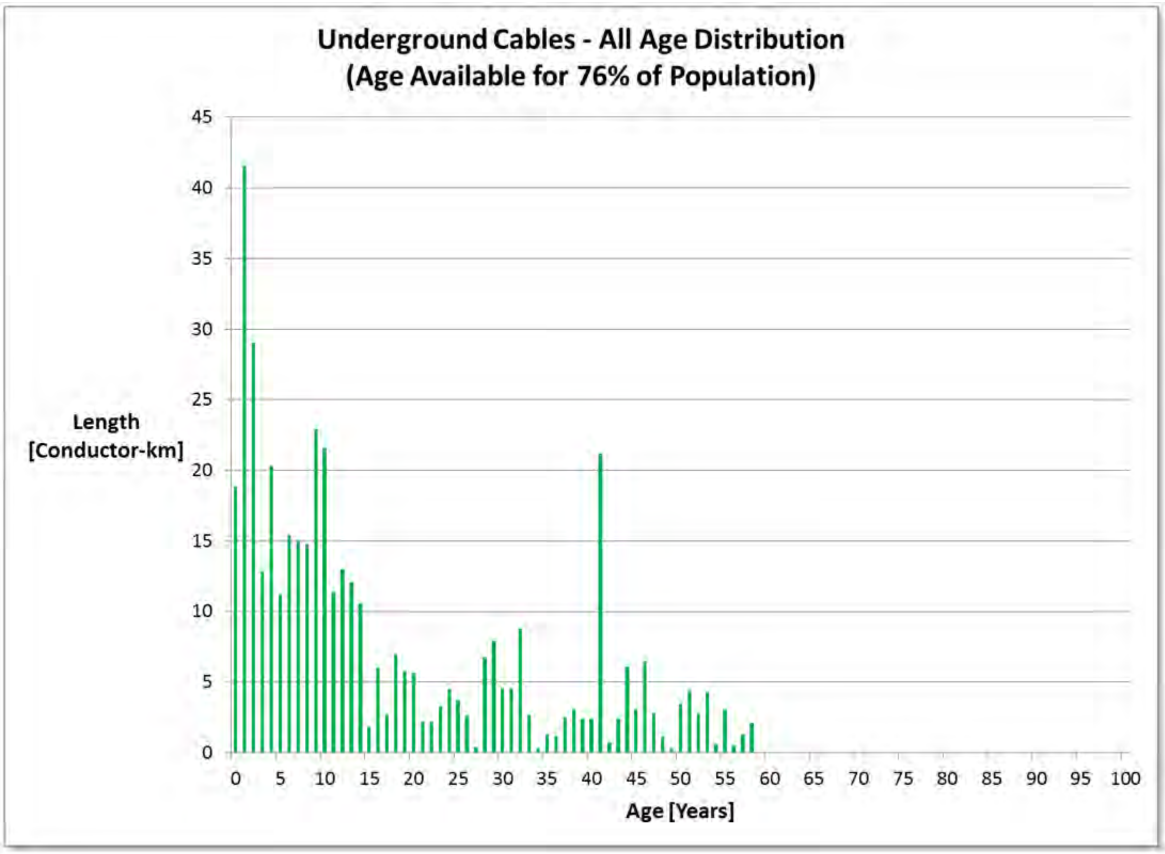

Figure 8-2 Age Distribution - Underground Cables

8.3 Health Index Results

There are 570 conductor-km of Main Feeder Underground Cables at NPEI. Of these, 433 conductor-km had sufficient data for Health Indexing.

The average Health Index for this asset group is 95% per conductor-km. Approximately 3% were found to be in poor or very poor condition.

The Health Index Results are as follows:

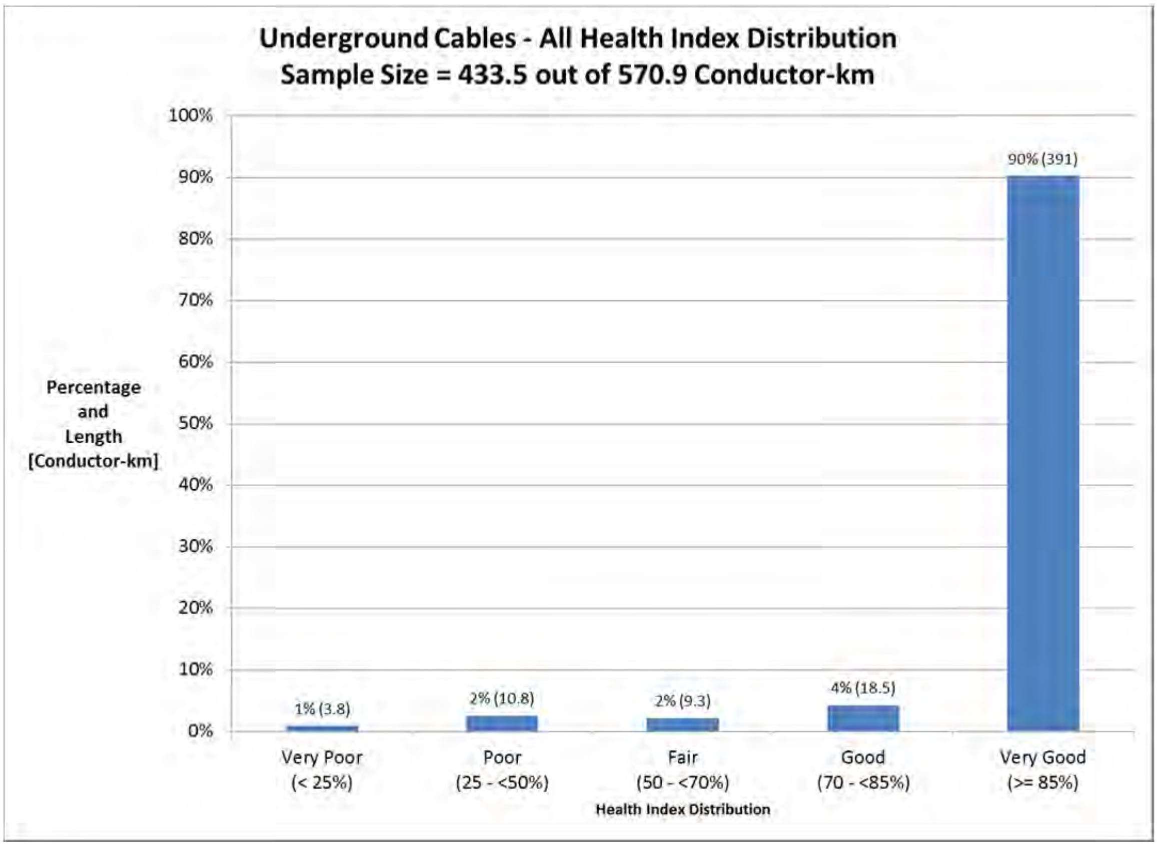

Figure 8-3 Health Index Distribution - Underground Cables (Conductor-km)

8.4 Condition-Based Flagged for Action Plan

Although Underground Cables are proactively addressed, the number of units flagged for action per year is estimated using the asset failure rate f(t).

The Flagged for Action Plan is based on the expected number of units that require action in a given year. In case it is not always be feasible to address assets as per the optimal plan, a "levelized" plan, based on accelerating action prior to expected time of action, will be given.

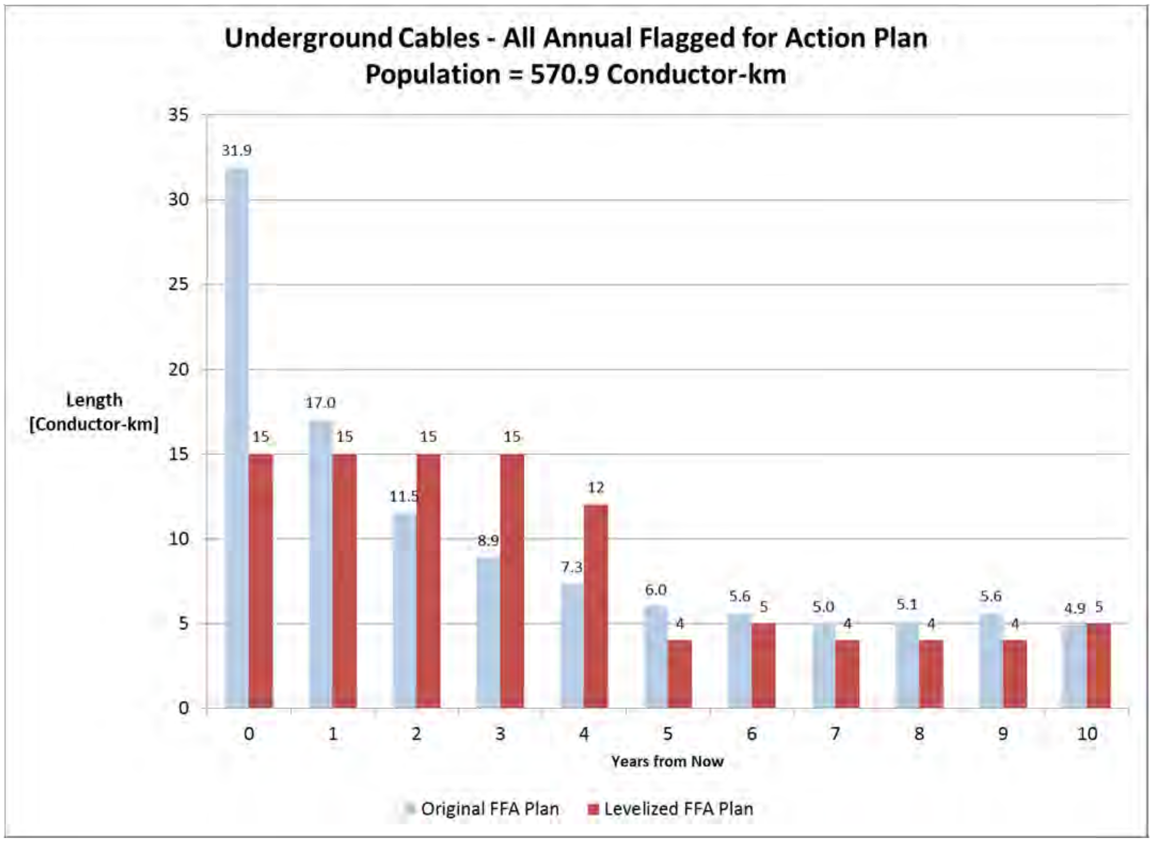

Figure 8-4 Flagged for Action Plan - Underground Cables

8.5 Data Analysis

Only age was available for Underground Cables.

8.5.1 Data Gaps

Although visual inspections and ultrasonic and infrared scans are conducted for Underground Cables, such data has yet to be incorporated into the Health Index. Specific and additional data that would improve the Health Index are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Splice & Termination	Physical Condition	☆☆	Cable splice	Under/over-compressed connector	On-site visual inspection
				Improper ground connection	
				Loose bolt	
			Cable termination	Sealing issue	
				Insulation erosion	
Test Data	Testing	☆☆☆	Cable segment	Test Methods: insulation resistance, AC withstand, partial discharge, dielectric loss, time domain reflectometry	Field Testing

8.5.2 Data Availability Distribution

As all the underground cables had no information other than age, the data availability distribution was not available.

9 Overhead Lines

9.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Overhead Lines. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

9.1.1 Condition and Sub-Condition Parameters

Table 9-1 Condition Parameters and Weights - Overhead Lines

Condition Parameter			Sub-Condition Parameter			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
	Age Limiter Factor				Figure 9-1	

9.1.2 Condition Parameter Criteria

<u>Age Limiting Factor</u>

In this project, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. Principle of applying the degradation survival curve is described in section II.2.1.

In this project, the parameters of Overhead Lines age limiting curve are shown in the following table, based on industry practice.

Table 9-2 Age Limiting Curve Parameters - Overhead Lines

Asset Type	α	β
Overhead Lines	**59.2788**	**4.364**

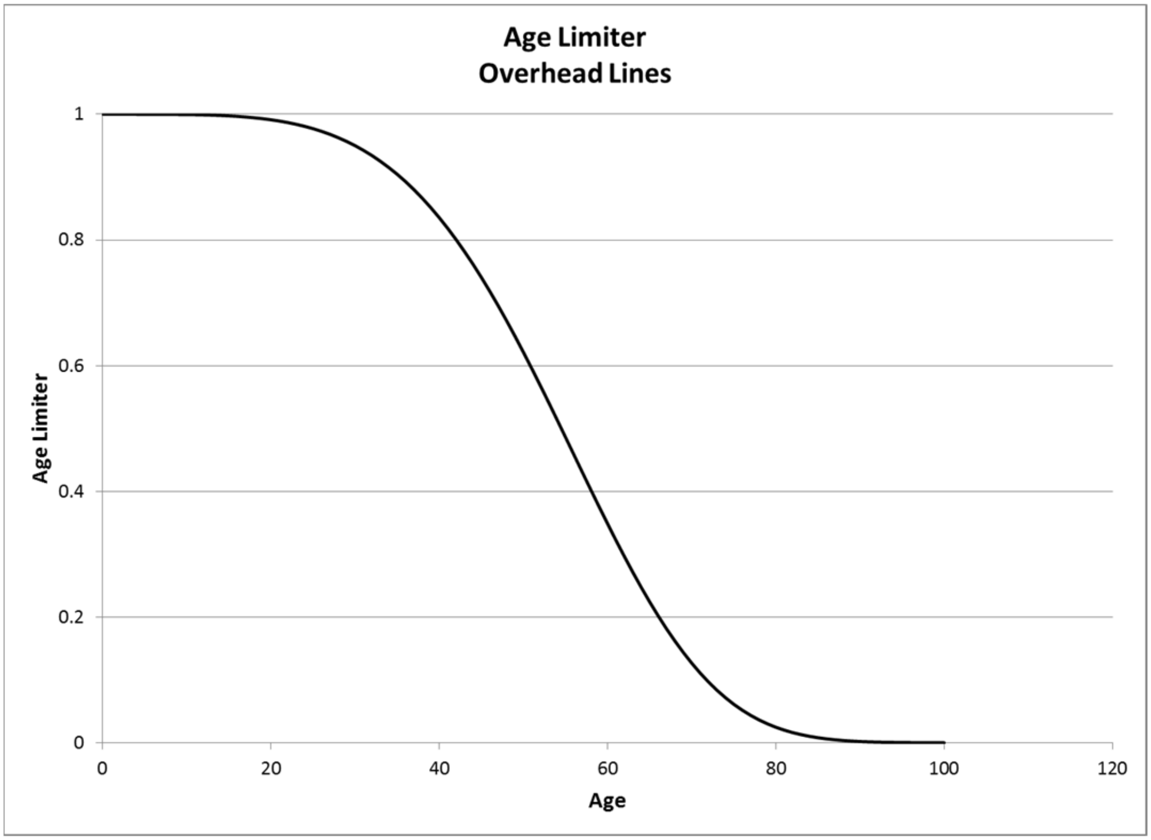

Figure 9-1 Age Limiting Factor Criteria - - Overhead Lines

9.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 38% of all cables. The average age was found to be 7 years/conductor-km.

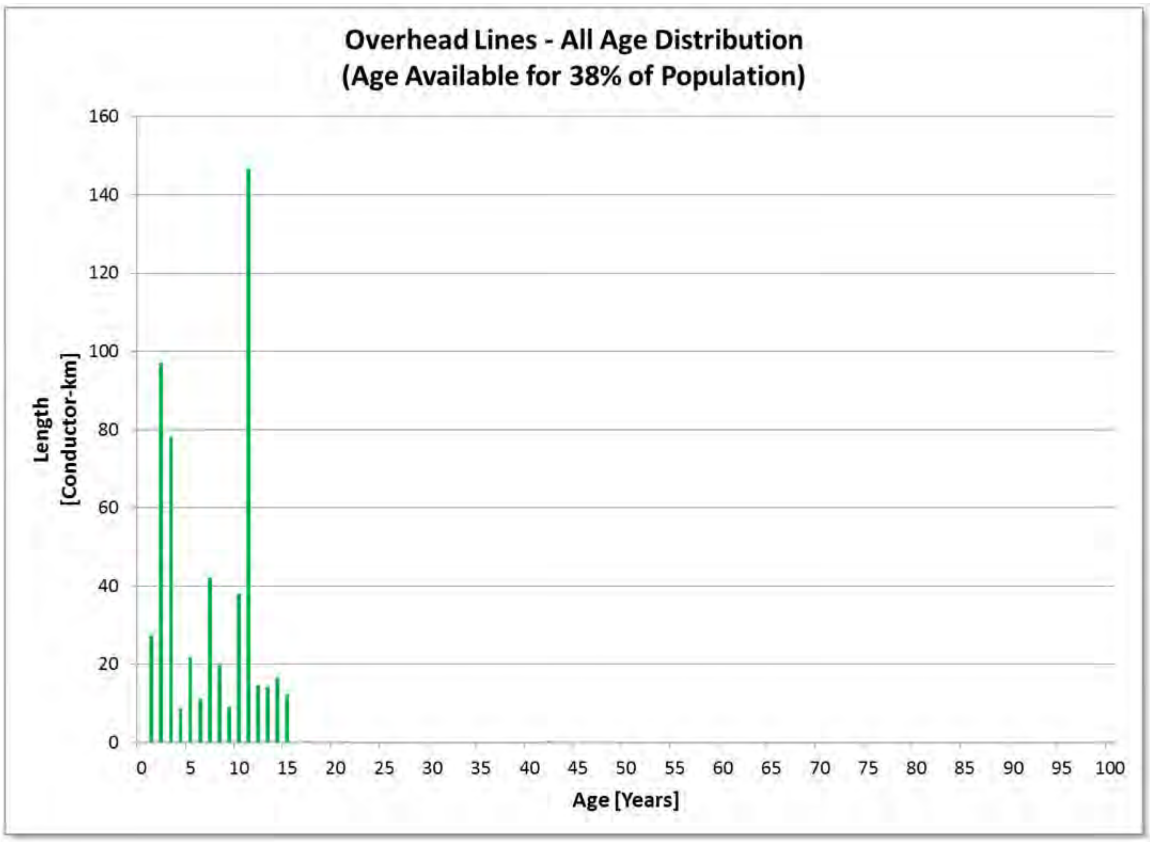

Figure 9-2 Age Distribution - Overhead Lines

9.3 Health Index Results

There were 1452 conductor-km of Overhead Lines at NPEI. Of these, 558 conductor-km had sufficient data for Health Indexing.

The average Health Index for this asset group is close to 100% per conductor-km. None of the segments were found to be in poor or very poor condition.

The Health Index Results are as follows:

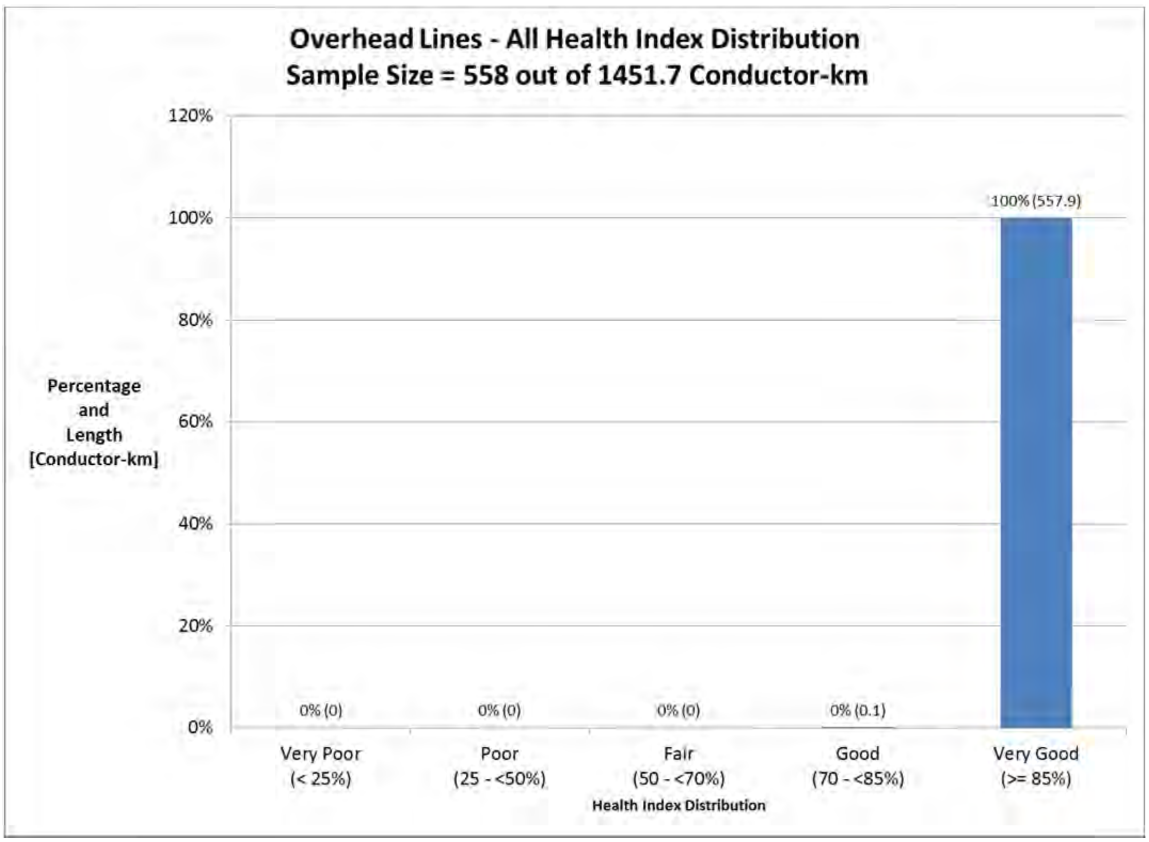

Figure 9-3 Health Index Distribution - Overhead Lines (Conductor-km)

9.4 Condition-Based Flagged for Action Plan

Although Overhead Lines are proactively addressed, the number of units flagged for action per year is estimated using the asset failure rate f(t).

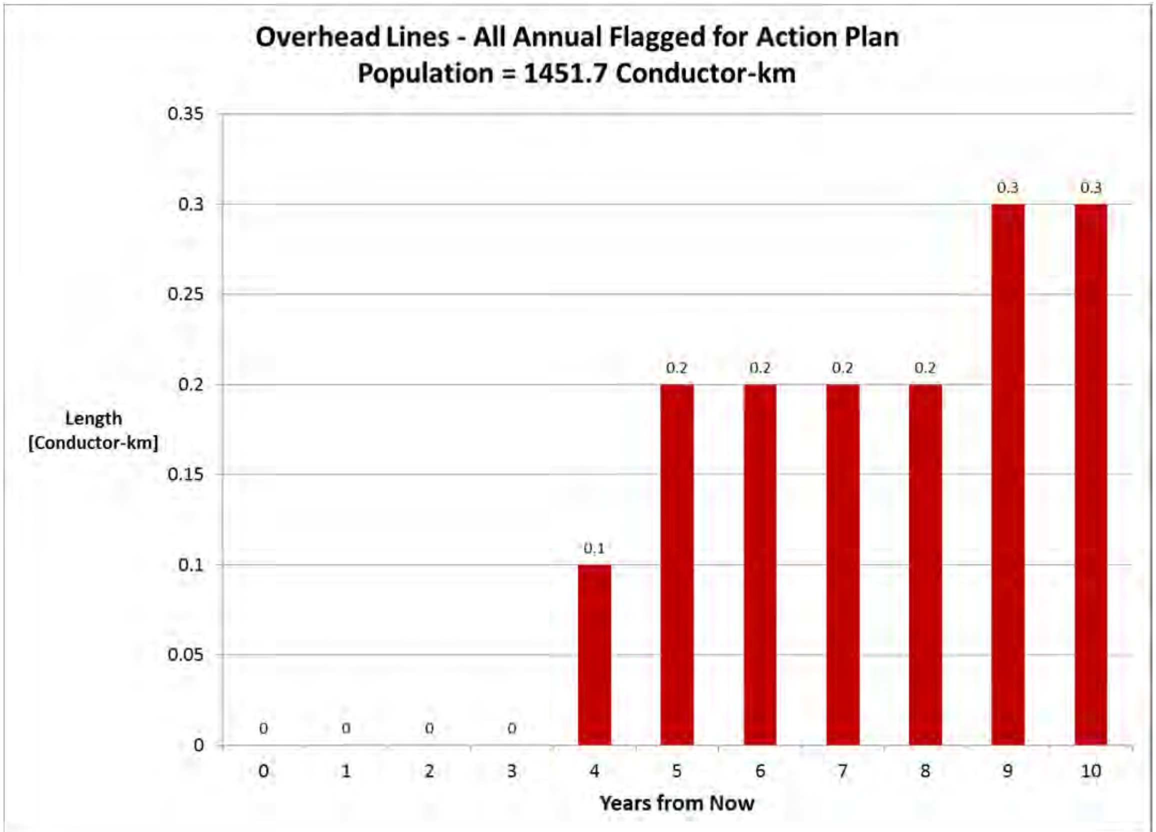

Figure 9-4 Flagged for Action Plan - Overhead Lines

9.5 Data Analysis

Only age was available for Overhead Lines.

9.5.1 Data Gaps

Although visual inspections and infrared scans are conducted for Overhead Lines, such data has yet to be incorporated into the Health Index. Specific and additional data that would improve the Health Index are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Splice & Termination	Physical Condition	☆ ☆	Conductor splice	Under/over-compressed connector	On-site visual inspection
				Loose bolt	
			Conductor	Sag issue	
				Broken strands	

9.5.2 Data Availability Distribution

As all the overhead lines had no information other than age, the data availability distribution was not available.

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Appendix G:
Grid Modernization Plan

niagara
peninsula
energy

Grid Modernization Investment Plan

Per: OEB Chapter 5 Consolidated Distribution System Plan
Filling Requirements – 5.1.1

November 29,
2019

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Executive Summary

Niagara Peninsula Energy Inc. (NPEI) has developed a Grid Modernization Investment Plan to provide to the Ontario Energy Board (OEB). The purpose of the plan is to outline NPEI's Grid Modernization goals and identify areas of investments. From NPEI's 2014-2019 DSP, NPEI has invested in smart grid technologies mainly focusing on building a wireless point-to-multi-point network (WiMAX network) and replacing old devices within our system. Over the past five years NPEI has established the majority of the backbone WiMAX network, brought some end point devices online, and replaced all of the old electromechanical devices in our system.

Moving forward, NPEI plans to continue its work to finish the backbone of our WiMAX network to ensure our entire system is reachable. With the completed WiMAX infrastructure, NPEI will focus on fully utilizing our WiMAX network to bring more end point smart devices online. These devices include Reclosers/Sectionalizers, Substation Switchgear, Line Fault Monitors, etc.

The investment in smart grid technologies, will aide NPEI in its day to day operations as well as its long term system planning. These devices will reduce restoration time during outages and assist the Control Room in determining the cause of outages. Obtaining more real time data and keeping historical information will help NPEI in its future system planning .Further, as Distributed Energy Resources (DER) continue to become more prevalent, the addition of smart grid technologies to our distribution system will be critical in ensuring NPEI is ready.

Introduction

As per OEB Chapter 5 Consolidated Distribution System Plan Filling Requirements – 5.1.1, NPEI is required to prepare plans for the development and implementation of a smart grid. Strategic investments must then be made in accordance with these plans to support Grid Modernization.

According to the Ontario Electricity Act, "smart grid" is defined as:

... advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of:

(a) Enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;

(b) Expanding opportunities to provide demand response, price information and load control to electricity customers;

(c) Accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or

(d) Supporting other objectives that may be prescribed by regulation.

Grid Modernization to date

From our 2014-2019 DSP, NPEI had a goal for implementing smart grid technologies across our system. The plan focused on the following areas:

(a) Upgrading archaic electromechanical devices to modern electronics with communication provisions;
(b) Establishing a communications network to remotely monitor and control all new electronic devices; and
(c) Automate key electronic devices and systems.

NPEI made significant progress implementing technology in these areas over the past 5 years. To date NPEI has:

(a) Eliminated all archaic electromechanical reclosers and installed electronically controlled vacuum reclosers. These devices included integrated smart relays for control and monitoring purposes with provision for communication.
(b) Built and deployed a wireless point-to-multi-point network (WiMAX network) utilizing a communications Industry Canada's allocated 1800-1830 MHz bandwidth. To date, 90% of the back-bone network is in service, this includes three (3) towers and nine (9) base stations.
(c) Installed and Commissioned smart end point devices at twelve (12) key locations on our distribution system communicating through our WiMAX network. This includes six (6) MS/DS substations, five (5) reclosers/sectionalizers, and one (1) DER generator.

In addition to the items listed above, NPEI also made significant progress and upgrades related to our SCADA system. This includes:

- Implementing a Disaster Recovery Plan by achieving redundancy in our SCADA server
- Upgrading to a new SCADA HMI platform
- Introduced our WiMAX network end point devices into our SCADA software. Previously, the WiMAX end point devices were viewed using HMI software separate from our SCADA software used for TS Station monitoring. Combining these two technologies allows for easier monitoring and control for our Control Room as well as better historical data for NPEI.
- Developed a standard implementation for monitoring and control of new DER connections. As the role of the LDC continues to evolve with DER connections, this will help NPEI be ready for these changes.

Grid Modernization Plan Moving Forward

NPEI plans to continue to invest in our grid modernization by continuing projects and goals set out in our previous DSP. This includes:

1. Completing the wireless point-to-multi-point network back-bone to ensure any end point device installed in our System can access this network.
2. Installing end point devices at our remaining Municipal Stations and reclosers. Prioritizing on stations and reclosers that will provide NPEI with the most control and flexibility.
3. Incorporating all new end point devices and DER connections into our new SCADA HMI system.

In addition to expanding and completing grid modernization plans from our 2014-2019 DSP, NPEI also plans to invest in the following areas of Grid Modernization:

1. Installation of smart Line Fault Indicators at key intersections within our system. These devices are installed on 3 phase lines, typically at tie points along main feeders. The endpoint devices can be connected into our SCADA system via our WiMAX network. The devices will help NPEI in two major areas:

    a. **Line Fault Detection:**

    In certain areas within our territory when an outage occurs, it can be difficult to locate the problem without patrolling the lines. These devices will reduce the down time and assist our crews in locating faults.

    b. **Line Current Monitoring:**

    As the devices will be tied into our SCADA monitoring system, it will allow our Control Room to monitor line current in real time at mid points along a Feeder. Traditionally, live Feeder monitoring was only achievable at Substation breakers and mid stream reclosers. Having this new data will help validate our system model for Load Flow studies and help ensure loads are balanced between phases.

2. With the new software improvements implemented into our SCADA system, NPEI will have better historical data available on our distribution system. The new data will help improve our system model for Load Flow studies, assist with Connection Impact Assessments of new DG connections, and provide another tool to be used for system planning. The new SCADA improvements may also lead to enhancements in our Outage Management System (OMS) as we begin to incorporate new devices and monitoring into our OMS. This will assist our Control Room and decrease restoration time during outages.

Appendix H:
Worst Performing Feeders Analysis

Worst Performing Feeder Analysis

Per: OEB Chapter 5 Consolidated Distribution System Plan
Filling Requirements – 5.3.1.b

February 7, 2020

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Executive Summary

NPEI use the following metrics; Customer Hours Interrupted (CHI); and number of Customers Interrupted (CI) to analyze feeder performance. These two metrics are directly related to SAIDI and SAIFI respectively. Planned outages and Loss of Supply are excluded from the outage data. Abnormal feeder configurations were not excluded. Abnormal feeder configuration occurs when additional customers are temporarily added to a feeder in order to support construction or maintenance work performed on an adjacent circuit.

NPEI uses the previous year's outage data to develop the worst 5 performing feeders list. The reason for using the previous year's data and concentrating on the worst 5 feeders is that if there are too many years the list may contain feeders that have been previously addressed and it would be difficult to address issues on more than 5 feeders in one year.

NPEI's focus on developing the worst performing feeders list is based on the feeders' contribution to overall system reliability as opposed to the reliability experienced by an average customer on the feeder.

The analysis based on both Customer Hours Interrupted (CHI) and Customers Interrupted (CI) indicated that four (4) feeders appear on both lists of worst performing feeders. The feeders identified were the 2508M2, 4501F1, 18M1, and 18M4.

The main causes for outages for each of these feeders during the previous year were Adverse Weather, Tree Contact and Defective Equipment. The majority of equipment problems related to either failed porcelain insulated switches and blown fuses. NPEI has experienced issues with older porcelain cutouts in that they tend to track and flash over resulting in outages during light rain, icy or foggy conditions. NPEI crews have standing directions to replace older porcelain cutouts with new polymeric cutouts whenever they are responding to a trouble call or service upgrade etc, involving these devices.

Many of the blown fuse and tree contact events also correspond to adverse weather events involving wind, ice or lightening. Adverse weather was also the most significant driver for the fifth worst feeders for each of CHI (2508M5) and for CI (3M51). On December 1, 2019 there was a Freezing Rain event in the Niagara Region that caused the 2508M5 Feeder Breaker to open. This event affected 1,293 customers for 255 minutes, this event alone equated to 5,515 Customer Hour Interruptions or 92% of the total Customer Hour Interruptions for the year 2019 on this feeder. On February 24, 2019 there was a High Wind Event that caused the Feeder Breaker for the 3M51 to open twice in the same day. These two events affected 2,858 customers twice equating to 5,716 Customer Interruptions or 5,877 or 97% of the total Customer Interruptions for the year 2019 on this feeder.

Introduction

NPEI has also successfully integrated its advanced meter infrastructure (AMI) to the InService Outage Management System (OMS). Real time reporting of outage and restoration notifications from the meter to the OMS provides instantaneous prediction of failed devices on the distribution system resulting in an improvement in response and restoration time and providing for more accurate recording of outage data.

NPEI monitors system reliability indices SAIDI, SAIFI, and CAIDI on a monthly basis. NPEI's outage management system (OMS) is the source of information for the 3 indices. Outage events are determined by the OMS based on the input of smart meter outage alarms and customer calls. The input of smart meter alarms provide a reliable start time for outage events as opposed to methods employed previously that relied on a customer's call. Upon receipt of a predicted outage, NPEI control room operators immediately dispatch field staff for investigation. Following restoration, crews identify the cause of the outage and restoration time on field based mobile devices. The restore time is compared to the restore notification from real time smart meter data and updated by NPEI operators. This process ensures the utmost accuracy in customer count, outage duration, and outage cause as related to service reliability indices.

Standard reports from NPEI's outage management system are available such that the overall service reliability indices can be summarized monthly. The indices are also summarized at the feeder level. Analysis of the indices allow NPEI to measure the success of operational and maintenance activities as well as whether capital expenditures are positively impacting system performance.

The feeder reliability indices are reviewed annually to identify year over year trending and identify poor performance. Feeders identified as having recurring poor performance levels, that are not attributed to an externally driven event, are analyzed to determine potential improvement measures.

There are no pre-defined regulatory metrics used to determine worst performing feeders (WPF). In assessing feeders that contribute negatively to reliability, NPEI use the following metrics; Customer Hours Interrupted (CHI), and number of Customers Interrupted (CI). These two metrics are directly related to SAIDI and SAIFI respectively. Planned outages and Loss of Supply are excluded from the outage data. Abnormal feeder configurations were not excluded. Abnormal feeder configuration occurs when additional customers are temporarily added to a feeder in order to support construction or maintenance work performed on an adjacent circuit.

NPEI uses the previous year’s outage data to develop the worst 5 performing feeders list. The reason for using the previous year’s data and concentrating on the worst 5 feeders is that if there are too many years the list may contain feeders that have been previously addressed and it would be difficult to address issues on more than 5 feeders in one year.

NPEI’s focus on developing the worst performing feeders list is based on the feeders’ contribution to overall system reliability as opposed to the reliability experienced by an average customer on the feeder.

Past 5 Years Feeder Performance

The following tables summarize feeder performance by their contribution to NPEI’s overall SAIFI and SAIDI statistics.

2015 Feeder Performance Summary
Sorted by SAIFI

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Beamsville TS	18M1	12341	13745	53002	0.233	0.259	0.898
Beamsville TS	18M2	9406	7296	53002	0.177	0.138	1.289
Vineland DS	4501F1	2996	6928	53002	0.057	0.131	0.432
Stanley TS	12M5	6286	4985	53002	0.119	0.094	1.261
Stanley TS	12M6	5100	4963	53002	0.096	0.094	1.028
Vineland DS	4501F2	8964	4933	53002	0.169	0.093	1.817
Niagara West TS	2508M2	3516	4164	53002	0.066	0.079	0.844
Stanley TS	12M41	5049	3548	53002	0.095	0.067	1.423
Murray TS	3M51	8700	3467	53002	0.164	0.065	2.509
Murray TS	3M17	1517	3341	53002	0.029	0.063	0.454
Stanley TS	12M32	478	3236	53002	0.009	0.061	0.148
Kalar TS	KM4	3173	3109	53002	0.060	0.059	1.021
Stanley TS	12M42	5734	2627	53002	0.108	0.050	2.183
Stanley TS	12M1	1453	2271	53002	0.027	0.043	0.640
Allanburg TS	45M7	3249	2253	53002	0.061	0.043	1.442
Murray TS	3M16	392	2036	53002	0.007	0.038	0.193
Beamsville TS	18M4	2699	1979	53002	0.051	0.037	1.364
Kalar TS	KM6	3167	1721	53002	0.060	0.032	1.840
Murray TS	3M26	1966	1636	53002	0.037	0.031	1.202
Murray TS	3M27	985	1564	53002	0.019	0.030	0.630
Kalar TS	KM8	1902	1229	53002	0.036	0.023	1.547
Murray TS	3M56	1014	1212	53002	0.019	0.023	0.836
Stanley TS	12M43	514	959	53002	0.010	0.018	0.536
Murray TS	3M54	1289	946	53002	0.024	0.018	1.363
Niagara West TS	2508M5	123	933	53002	0.002	0.018	0.132
Kalar TS	KM1	1097	718	53002	0.021	0.014	1.528
Stanley TS	12M33	1105	713	53002	0.021	0.013	1.549
Niagara West TS	3M14	260	697	53002	0.005	0.013	0.373
Beamsville TS	18M3	261	252	53002	0.005	0.005	1.036
Niagara West TS	2508M4	333	175	53002	0.006	0.003	1.902
Kalar TS	KM3	349	166	53002	0.007	0.003	2.101
Murray TS	3M30	249	124	53002	0.005	0.002	2.010
Kalar TS	KM7	366	98	53002	0.007	0.002	3.736
Stanley TS	12M31	131	73	53002	0.002	0.001	1.793
Murray TS	3M15	7	43	53002	0.000	0.001	0.160
Kalar TS	KM2	241	37	53002	0.005	0.001	6.519
Murray TS	3M52	74	33	53002	0.001	0.001	2.248
Kalar TS	KM5	49	30	53002	0.001	0.001	1.646
Murray TS	3M29	20	14	53002	0.000	0.000	1.414
Murray TS	3M18	0	1	53002	0.000	0.000	0.083

	Lowest Level of Feeder Performance
	Highest Level of Feeder Performance

2015 Feeder Performance Summary
Sorted by SAIDI

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Stanley TS	18M1	12341	13745	53002	0.233	0.259	0.898
Beamsville TS	18M2	9406	7296	53002	0.177	0.138	1.289
Vineland DS	4501F2	8964	4933	53002	0.169	0.093	1.817
Murray TS	3M51	8700	3467	53002	0.164	0.065	2.509
Stanley TS	12M5	6286	4985	53002	0.119	0.094	1.261
Stanley TS	12M42	5734	2627	53002	0.108	0.050	2.183
Stanley TS	12M6	5100	4963	53002	0.096	0.094	1.028
Stanley TS	12M41	5049	3548	53002	0.095	0.067	1.423
Beamsville TS	2508M2	3516	4164	53002	0.066	0.079	0.844
Allanburg TS	45M7	3249	2253	53002	0.061	0.043	1.442
Kalar TS	KM4	3173	3109	53002	0.060	0.059	1.021
Kalar TS	KM6	3167	1721	53002	0.060	0.032	1.840
Vineland DS	4501F1	2996	6928	53002	0.057	0.131	0.432
Beamsville TS	18M4	2699	1979	53002	0.051	0.037	1.364
Murray TS	3M26	1966	1636	53002	0.037	0.031	1.202
Kalar TS	KM8	1902	1229	53002	0.036	0.023	1.547
Murray TS	3M17	1517	3341	53002	0.029	0.063	0.454
Stanley TS	12M1	1453	2271	53002	0.027	0.043	0.640
Murray TS	3M54	1289	946	53002	0.024	0.018	1.363
Stanley TS	12M33	1105	713	53002	0.021	0.013	1.549
Kalar TS	KM1	1097	718	53002	0.021	0.014	1.528
Murray TS	3M56	1014	1212	53002	0.019	0.023	0.836
Murray TS	3M27	985	1564	53002	0.019	0.030	0.630
Stanley TS	12M43	514	959	53002	0.010	0.018	0.536
Stanley TS	12M32	478	3236	53002	0.009	0.061	0.148
Murray TS	3M16	392	2036	53002	0.007	0.038	0.193
Kalar TS	KM7	366	98	53002	0.007	0.002	3.736
Kalar TS	KM3	349	166	53002	0.007	0.003	2.101
Niagara West TS	2508M4	333	175	53002	0.006	0.003	1.902
Beamsville TS	18M3	261	252	53002	0.005	0.005	1.036
Niagara West TS	3M14	260	697	53002	0.005	0.013	0.373
Murray TS	3M30	249	124	53002	0.005	0.002	2.010
Kalar TS	KM2	241	37	53002	0.005	0.001	6.519
Stanley TS	12M31	131	73	53002	0.002	0.001	1.793
Niagara West TS	2508M5	123	933	53002	0.002	0.018	0.132
Murray TS	3M52	74	33	53002	0.001	0.001	2.248
Kalar TS	KM5	49	30	53002	0.001	0.001	1.646
Murray TS	3M29	20	14	53002	0.000	0.000	1.414
Murray TS	3M15	7	43	53002	0.000	0.001	0.160
Murray TS	3M18	0	1	53002	0.000	0.000	0.083

	Lowest Level of Feeder Performance
	Highest Level of Feeder Performance

2015 Feeder Performance Summary

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Allanburg TS	45M7	3249	2253	53002	0.061	0.043	1.442
Beamsville TS	18M1	12341	13745	53002	0.233	0.259	0.898
Beamsville TS	18M2	9406	7296	53002	0.177	0.138	1.289
Beamsville TS	18M3	261	252	53002	0.005	0.005	1.036
Beamsville TS	18M4	2699	1979	53002	0.051	0.037	1.364
Kalar TS	KM1	1097	718	53002	0.021	0.014	1.528
Kalar TS	KM2	241	37	53002	0.005	0.001	6.519
Kalar TS	KM3	349	166	53002	0.007	0.003	2.101
Kalar TS	KM4	3173	3109	53002	0.060	0.059	1.021
Kalar TS	KM5	49	30	53002	0.001	0.001	1.646
Kalar TS	KM6	3167	1721	53002	0.060	0.032	1.840
Kalar TS	KM7	366	98	53002	0.007	0.002	3.736
Kalar TS	KM8	1902	1229	53002	0.036	0.023	1.547
Murray TS	3M14	260	697	53002	0.005	0.013	0.373
Murray TS	3M15	7	43	53002	0.000	0.001	0.160
Murray TS	3M16	392	2036	53002	0.007	0.038	0.193
Murray TS	3M17	1517	3341	53002	0.029	0.063	0.454
Murray TS	3M18	0	1	53002	0.000	0.000	0.083
Murray TS	3M26	1966	1636	53002	0.037	0.031	1.202
Murray TS	3M27	985	1564	53002	0.019	0.030	0.630
Murray TS	3M29	20	14	53002	0.000	0.000	1.414
Murray TS	3M30	249	124	53002	0.005	0.002	2.010
Murray TS	3M51	8700	3467	53002	0.164	0.065	2.509
Murray TS	3M52	74	33	53002	0.001	0.001	2.248
Murray TS	3M54	1289	946	53002	0.024	0.018	1.363
Murray TS	3M56	1014	1212	53002	0.019	0.023	0.836
Niagara West TS	2508M2	3516	4164	53002	0.066	0.079	0.844
Niagara West TS	2508M4	333	175	53002	0.006	0.003	1.902
Niagara West TS	2508M5	123	933	53002	0.002	0.018	0.132
Stanley TS	12M1	1453	2271	53002	0.027	0.043	0.640
Stanley TS	12M31	131	73	53002	0.002	0.001	1.793
Stanley TS	12M32	478	3236	53002	0.009	0.061	0.148
Stanley TS	12M33	1105	713	53002	0.021	0.013	1.549
Stanley TS	12M41	5049	3548	53002	0.095	0.067	1.423
Stanley TS	12M42	5734	2627	53002	0.108	0.050	2.183
Stanley TS	12M43	514	959	53002	0.010	0.018	0.536
Stanley TS	12M5	6286	4985	53002	0.119	0.094	1.261
Stanley TS	12M6	5100	4963	53002	0.096	0.094	1.028
Vineland DS	4501F1	2996	6928	53002	0.057	0.131	0.432
Vineland DS	4501F2	8964	4933	53002	0.169	0.093	1.817

2016 Feeder Performance Summary
Sorted by SAIFI

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Kalar TS	KM4	8360	9629	53671	0.156	0.179	0.868
Niagara West TS	2508M2	2427	8308	53671	0.045	0.155	0.292
Murray TS	3M27	2199	4558	53671	0.041	0.085	0.482
Kalar TS	KM8	6089	3740	53671	0.113	0.070	1.628
Beamsville TS	18M1	3108	3596	53671	0.058	0.067	0.864
Murray TS	3M17	5062	3499	53671	0.094	0.065	1.447
Kalar TS	KM7	5734	3348	53671	0.107	0.062	1.713
Stanley TS	12M33	4342	3270	53671	0.081	0.061	1.328
Stanley TS	12M41	1297	3031	53671	0.024	0.056	0.428
Murray TS	3M30	199	2905	53671	0.004	0.054	0.069
Vineland DS	4501F2	5207	2684	53671	0.097	0.050	1.940
Stanley TS	12M6	6134	2646	53671	0.114	0.049	2.318
Beamsville TS	18M2	2595	2602	53671	0.048	0.048	0.997
Stanley TS	12M1	2608	2502	53671	0.049	0.047	1.042
Kalar TS	KM3	2337	2105	53671	0.044	0.039	1.110
Allanburg TS	45M7	8726	2098	53671	0.163	0.039	4.159
Niagara West TS	2508M5	1455	1951	53671	0.027	0.036	0.746
Beamsville TS	18M4	813	1893	53671	0.015	0.035	0.430
Kalar TS	KM6	3571	1645	53671	0.067	0.031	2.171
Kalar TS	KM2	856	1415	53671	0.016	0.026	0.605
Murray TS	3M26	712	1122	53671	0.013	0.021	0.634
Vineland DS	4501F1	1735	1065	53671	0.032	0.020	1.629
Murray TS	3M56	430	797	53671	0.008	0.015	0.539
Stanley TS	12M31	983	661	53671	0.018	0.012	1.487
Niagara West TS	2508M4	448	621	53671	0.008	0.012	0.722
Murray TS	3M54	705	596	53671	0.013	0.011	1.183
Stanley TS	12M5	2023	505	53671	0.038	0.009	4.007
Kalar TS	KM5	829	483	53671	0.015	0.009	1.717
Beamsville TS	18M3	576	467	53671	0.011	0.009	1.233
Murray TS	3M51	362	229	53671	0.007	0.004	1.580
Murray TS	3M52	213	199	53671	0.004	0.004	1.070
Stanley TS	12M43	245	98	53671	0.005	0.002	2.504
Stanley TS	12M32	143	78	53671	0.003	0.001	1.835
Stanley TS	12M42	85	73	53671	0.002	0.001	1.166
Stanley TS	12M4	418	70	53671	0.008	0.001	5.978
Murray TS	3M29	190	53	53671	0.004	0.001	3.586
Murray TS	3M16	120	43	53671	0.002	0.001	2.780
Murray TS	3M14	10	18	53671	0.000	0.000	0.567
Kalar TS	KM1	22	15	53671	0.000	0.000	1.437
Murray TS	3M15	0	0	53671	0.000	0.000	0.000

(orange)	Lowest Level of Feeder Performance
(green)	Highest Level of Feeder Performance

2016 Feeder Performance Summary
Sorted by SAIDI

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Allanburg TS	45M7	8726	2098	53671	0.163	0.039	4.159
Kalar TS	KM4	8360	9629	53671	0.156	0.179	0.868
Stanley TS	12M6	6134	2646	53671	0.114	0.049	2.318
Kalar TS	KM8	6089	3740	53671	0.113	0.070	1.628
Kalar TS	KM7	5734	3348	53671	0.107	0.062	1.713
Vineland DS	4501F2	5207	2684	53671	0.097	0.050	1.940
Murray TS	3M17	5062	3499	53671	0.094	0.065	1.447
Stanley TS	12M33	4342	3270	53671	0.081	0.061	1.328
Kalar TS	KM6	3571	1645	53671	0.067	0.031	2.171
Beamsville TS	18M1	3108	3596	53671	0.058	0.067	0.864
Stanley TS	12M1	2608	2502	53671	0.049	0.047	1.042
Beamsville TS	18M2	2595	2602	53671	0.048	0.048	0.997
Niagara West TS	2508M2	2427	8308	53671	0.045	0.155	0.292
Kalar TS	KM3	2337	2105	53671	0.044	0.039	1.110
Murray TS	3M27	2199	4558	53671	0.041	0.085	0.482
Stanley TS	12M5	2023	505	53671	0.038	0.009	4.007
Vineland DS	4501F1	1735	1065	53671	0.032	0.020	1.629
Niagara West TS	2508M5	1455	1951	53671	0.027	0.036	0.746
Stanley TS	12M41	1297	3031	53671	0.024	0.056	0.428
Stanley TS	12M31	983	661	53671	0.018	0.012	1.487
Kalar TS	KM2	856	1415	53671	0.016	0.026	0.605
Kalar TS	KM5	829	483	53671	0.015	0.009	1.717
Beamsville TS	18M4	813	1893	53671	0.015	0.035	0.430
Murray TS	3M26	712	1122	53671	0.013	0.021	0.634
Murray TS	3M54	705	596	53671	0.013	0.011	1.183
Beamsville TS	18M3	576	467	53671	0.011	0.009	1.233
Niagara West TS	2508M4	448	621	53671	0.008	0.012	0.722
Murray TS	3M56	430	797	53671	0.008	0.015	0.539
Stanley TS	12M4	418	70	53671	0.008	0.001	5.978
Murray TS	3M51	362	229	53671	0.007	0.004	1.580
Stanley TS	12M43	245	98	53671	0.005	0.002	2.504
Murray TS	3M52	213	199	53671	0.004	0.004	1.070
Murray TS	3M30	199	2905	53671	0.004	0.054	0.069
Murray TS	3M29	190	53	53671	0.004	0.001	3.586
Stanley TS	12M32	143	78	53671	0.003	0.001	1.835
Murray TS	3M16	120	43	53671	0.002	0.001	2.780
Stanley TS	12M42	85	73	53671	0.002	0.001	1.166
Kalar TS	KM1	22	15	53671	0.000	0.000	1.437
Murray TS	3M14	10	18	53671	0.000	0.000	0.567
Murray TS	3M15	0	0	53671	0.000	0.000	0.000

(orange)	Lowest Level of Feeder Performance
(green)	Highest Level of Feeder Performance

2016 Feeder Performance Summary

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Allanburg TS	45M7	8726	2098	53671	0.163	0.039	4.159
Beamsville TS	18M1	3108	3596	53671	0.058	0.067	0.864
Beamsville TS	18M2	2595	2602	53671	0.048	0.048	0.997
Beamsville TS	18M3	576	467	53671	0.011	0.009	1.233
Beamsville TS	18M4	813	1893	53671	0.015	0.035	0.430
Kalar TS	KM1	22	15	53671	0.000	0.000	1.437
Kalar TS	KM2	856	1415	53671	0.016	0.026	0.605
Kalar TS	KM3	2337	2105	53671	0.044	0.039	1.110
Kalar TS	KM4	8360	9629	53671	0.156	0.179	0.868
Kalar TS	KM5	829	483	53671	0.015	0.009	1.717
Kalar TS	KM6	3571	1645	53671	0.067	0.031	2.171
Kalar TS	KM7	5734	3348	53671	0.107	0.062	1.713
Kalar TS	KM8	6089	3740	53671	0.113	0.070	1.628
Murray TS	3M14	10	18	53671	0.000	0.000	0.567
Murray TS	3M15	0	0	53671	0.000	0.000	0.000
Murray TS	3M16	120	43	53671	0.002	0.001	2.780
Murray TS	3M17	5062	3499	53671	0.094	0.065	1.447
Murray TS	3M26	712	1122	53671	0.013	0.021	0.634
Murray TS	3M27	2199	4558	53671	0.041	0.085	0.482
Murray TS	3M29	190	53	53671	0.004	0.001	3.586
Murray TS	3M30	199	2905	53671	0.004	0.054	0.069
Murray TS	3M51	362	229	53671	0.007	0.004	1.580
Murray TS	3M52	213	199	53671	0.004	0.004	1.070
Murray TS	3M54	705	596	53671	0.013	0.011	1.183
Murray TS	3M56	430	797	53671	0.008	0.015	0.539
Niagara West TS	2508M2	2427	8308	53671	0.045	0.155	0.292
Niagara West TS	2508M4	448	621	53671	0.008	0.012	0.722
Niagara West TS	2508M5	1455	1951	53671	0.027	0.036	0.746
Stanley TS	12M1	2608	2502	53671	0.049	0.047	1.042
Stanley TS	12M31	983	661	53671	0.018	0.012	1.487
Stanley TS	12M32	143	78	53671	0.003	0.001	1.835
Stanley TS	12M33	4342	3270	53671	0.081	0.061	1.328
Stanley TS	12M4	418	70	53671	0.008	0.001	5.978
Stanley TS	12M41	1297	3031	53671	0.024	0.056	0.428
Stanley TS	12M42	85	73	53671	0.002	0.001	1.166
Stanley TS	12M43	245	98	53671	0.005	0.002	2.504
Stanley TS	12M5	2023	505	53671	0.038	0.009	4.007
Stanley TS	12M6	6134	2646	53671	0.114	0.049	2.318
Vineland DS	4501F1	1735	1065	53671	0.032	0.020	1.629
Vineland DS	4501F2	5207	2684	53671	0.097	0.050	1.940

2017 Feeder Performance Summary
Sorted by SAIFI

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Kalar TS	KM4	3835	9707	55013	0.070	0.176	0.395
Vineland DS	4501F1	7146	9706	55013	0.130	0.176	0.736
Stanley TS	12M5	1314	8494	55013	0.024	0.154	0.155
Murray TS	3M17	1487	6592	55013	0.027	0.120	0.226
Stanley TS	12M41	7726	5465	55013	0.140	0.099	1.414
Stanley TS	12M6	9383	5266	55013	0.171	0.096	1.782
Allanburg TS	45M7	8844	5023	55013	0.161	0.091	1.761
Stanley TS	12M33	2876	4928	55013	0.052	0.090	0.584
Stanley TS	12M1	1513	4580	55013	0.027	0.083	0.330
Murray TS	3M30	4345	4400	55013	0.079	0.080	0.987
Murray TS	3M27	2081	3530	55013	0.038	0.064	0.589
Beamsville TS	18M4	4282	3206	55013	0.078	0.058	1.336
Vineland DS	4501F2	3201	2998	55013	0.058	0.054	1.068
Stanley TS	12M31	1672	2947	55013	0.030	0.054	0.567
Kalar TS	KM3	3233	2071	55013	0.059	0.038	1.561
Beamsville TS	18M2	3337	1905	55013	0.061	0.035	1.752
Murray TS	3M56	2528	1858	55013	0.046	0.034	1.361
Kalar TS	KM2	2128	1631	55013	0.039	0.030	1.305
Beamsville TS	18M1	841	1288	55013	0.015	0.023	0.653
Kalar TS	KM6	1693	921	55013	0.031	0.017	1.838
Kalar TS	KM1	801	771	55013	0.015	0.014	1.039
Niagara West TS	2508M2	2357	653	55013	0.043	0.012	3.610
Kalar TS	KM5	70	528	55013	0.001	0.010	0.133
Niagara West TS	2508M5	103	503	55013	0.002	0.009	0.205
Niagara West TS	2508M4	307	423	55013	0.006	0.008	0.726
Murray TS	3M51	413	339	55013	0.008	0.006	1.218
Stanley TS	12M43	574	290	55013	0.010	0.005	1.979
Stanley TS	12M32	469	261	55013	0.009	0.005	1.798
Murray TS	3M54	308	260	55013	0.006	0.005	1.184
Murray TS	3M26	257	94	55013	0.005	0.002	2.737
Kalar TS	KM8	167	90	55013	0.003	0.002	1.855
Murray TS	3M14	83	63	55013	0.002	0.001	1.324
Kalar TS	KM7	82	59	55013	0.001	0.001	1.394
Stanley TS	12M42	58	56	55013	0.001	0.001	1.039
Beamsville TS	18M3	92	41	55013	0.002	0.001	2.236
Stanley TS	12M4	50	31	55013	0.001	0.001	1.622
Murray TS	3M29	5	8	55013	0.000	0.000	0.588
Murray TS	3M16	6	6	55013	0.000	0.000	1.003
Murray TS	3M52	1	2	55013	0.000	0.000	0.533
Murray TS	3M15	0	0	55013	0.000	0.000	0.000

(orange)	Lowest Level of Feeder Performance
(green)	Highest Level of Feeder Performance

2017 Feeder Performance Summary
Sorted by SAIDI

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Stanley TS	12M6	9383	5266	55013	0.171	0.096	1.782
Allanburg TS	45M7	8844	5023	55013	0.161	0.091	1.761
Stanley TS	12M41	7726	5465	55013	0.140	0.099	1.414
Vineland DS	4501F1	7146	9706	55013	0.130	0.176	0.736
Murray TS	3M30	4345	4400	55013	0.079	0.080	0.987
Beamsville TS	18M4	4282	3206	55013	0.078	0.058	1.336
Kalar TS	KM4	3835	9707	55013	0.070	0.176	0.395
Beamsville TS	18M2	3337	1905	55013	0.061	0.035	1.752
Kalar TS	KM3	3233	2071	55013	0.059	0.038	1.561
Vineland DS	4501F2	3201	2998	55013	0.058	0.054	1.068
Stanley TS	12M33	2876	4928	55013	0.052	0.090	0.584
Murray TS	3M56	2528	1858	55013	0.046	0.034	1.361
Niagara West TS	2508M2	2357	653	55013	0.043	0.012	3.610
Kalar TS	KM2	2128	1631	55013	0.039	0.030	1.305
Murray TS	3M27	2081	3530	55013	0.038	0.064	0.589
Kalar TS	KM6	1693	921	55013	0.031	0.017	1.838
Stanley TS	12M31	1672	2947	55013	0.030	0.054	0.567
Stanley TS	12M1	1513	4580	55013	0.027	0.083	0.330
Murray TS	3M17	1487	6592	55013	0.027	0.120	0.226
Stanley TS	12M5	1314	8494	55013	0.024	0.154	0.155
Beamsville TS	18M1	841	1288	55013	0.015	0.023	0.653
Kalar TS	KM1	801	771	55013	0.015	0.014	1.039
Stanley TS	12M43	574	290	55013	0.010	0.005	1.979
Stanley TS	12M32	469	261	55013	0.009	0.005	1.798
Murray TS	3M51	413	339	55013	0.008	0.006	1.218
Murray TS	3M54	308	260	55013	0.006	0.005	1.184
Niagara West TS	2508M4	307	423	55013	0.006	0.008	0.726
Murray TS	3M26	257	94	55013	0.005	0.002	2.737
Kalar TS	KM8	167	90	55013	0.003	0.002	1.855
Niagara West TS	2508M5	103	503	55013	0.002	0.009	0.205
Beamsville TS	18M3	92	41	55013	0.002	0.001	2.236
Murray TS	3M14	83	63	55013	0.002	0.001	1.324
Kalar TS	KM7	82	59	55013	0.001	0.001	1.394
Kalar TS	KM5	70	528	55013	0.001	0.010	0.133
Stanley TS	12M42	58	56	55013	0.001	0.001	1.039
Stanley TS	12M4	50	31	55013	0.001	0.001	1.622
Murray TS	3M16	6	6	55013	0.000	0.000	1.003
Murray TS	3M29	5	8	55013	0.000	0.000	0.588
Murray TS	3M52	1	2	55013	0.000	0.000	0.533
Murray TS	3M15	0	0	55013	0.000	0.000	0.000

	Lowest Level of Feeder Performance
	Highest Level of Feeder Performance

2017 Feeder Performance Summary

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Allanburg TS	45M7	8844	5023	55013	0.161	0.091	1.761
Beamsville TS	18M1	841	1288	55013	0.015	0.023	0.653
Beamsville TS	18M2	3337	1905	55013	0.061	0.035	1.752
Beamsville TS	18M3	92	41	55013	0.002	0.001	2.236
Beamsville TS	18M4	4282	3206	55013	0.078	0.058	1.336
Kalar TS	KM1	801	771	55013	0.015	0.014	1.039
Kalar TS	KM2	2128	1631	55013	0.039	0.030	1.305
Kalar TS	KM3	3233	2071	55013	0.059	0.038	1.561
Kalar TS	KM4	3835	9707	55013	0.070	0.176	0.395
Kalar TS	KM5	70	528	55013	0.001	0.010	0.133
Kalar TS	KM6	1693	921	55013	0.031	0.017	1.838
Kalar TS	KM7	82	59	55013	0.001	0.001	1.394
Kalar TS	KM8	167	90	55013	0.003	0.002	1.855
Murray TS	3M14	83	63	55013	0.002	0.001	1.324
Murray TS	3M15	0	0	55013	0.000	0.000	0.000
Murray TS	3M16	6	6	55013	0.000	0.000	1.003
Murray TS	3M17	1487	6592	55013	0.027	0.120	0.226
Murray TS	3M26	257	94	55013	0.005	0.002	2.737
Murray TS	3M27	2081	3530	55013	0.038	0.064	0.589
Murray TS	3M29	5	8	55013	0.000	0.000	0.588
Murray TS	3M30	4345	4400	55013	0.079	0.080	0.987
Murray TS	3M51	413	339	55013	0.008	0.006	1.218
Murray TS	3M52	1	2	55013	0.000	0.000	0.533
Murray TS	3M54	308	260	55013	0.006	0.005	1.184
Murray TS	3M56	2528	1858	55013	0.046	0.034	1.361
Niagara West TS	2508M2	2357	653	55013	0.043	0.012	3.610
Niagara West TS	2508M4	307	423	55013	0.006	0.008	0.726
Niagara West TS	2508M5	103	503	55013	0.002	0.009	0.205
Stanley TS	12M1	1513	4580	55013	0.027	0.083	0.330
Stanley TS	12M31	1672	2947	55013	0.030	0.054	0.567
Stanley TS	12M32	469	261	55013	0.009	0.005	1.798
Stanley TS	12M33	2876	4928	55013	0.052	0.090	0.584
Stanley TS	12M4	50	31	55013	0.001	0.001	1.622
Stanley TS	12M41	7726	5465	55013	0.140	0.099	1.414
Stanley TS	12M42	58	56	55013	0.001	0.001	1.039
Stanley TS	12M43	574	290	55013	0.010	0.005	1.979
Stanley TS	12M5	1314	8494	55013	0.024	0.154	0.155
Stanley TS	12M6	9383	5266	55013	0.171	0.096	1.782
Vineland DS	4501F1	7146	9706	55013	0.130	0.176	0.736
Vineland DS	4501F2	3201	2998	55013	0.058	0.054	1.068

2018 Feeder Performance Summary
Sorted by SAIFI

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Niagara West TS	2508M2	8681	14932	55811	0.156	0.268	0.581
Murray TS	3M17	8204	13534	55811	0.147	0.242	0.606
Vineland DS	4501F1	10154	10096	55811	0.182	0.181	1.006
Murray TS	3M51	11418	8759	55811	0.205	0.157	1.304
Vineland DS	4501F2	19769	7478	55811	0.354	0.134	2.644
Beamsville TS	18M4	8106	5174	55811	0.145	0.093	1.567
Murray TS	3M30	2496	4734	55811	0.045	0.085	0.527
Beamsville TS	18M2	12636	4635	55811	0.226	0.083	2.726
Murray TS	3M27	3719	4393	55811	0.067	0.079	0.847
Allanburg TS	45M7	6595	3823	55811	0.118	0.068	1.725
Niagara West TS	2508M5	12013	3684	55811	0.215	0.066	3.261
Kalar TS	KM6	5272	3446	55811	0.094	0.062	1.530
Kalar TS	KM3	2754	3226	55811	0.049	0.058	0.854
Kalar TS	KM4	677	3024	55811	0.012	0.054	0.224
Murray TS	3M56	1916	2969	55811	0.034	0.053	0.645
Stanley TS	12M6	943	2736	55811	0.017	0.049	0.345
Stanley TS	12M41	4421	2599	55811	0.079	0.047	1.701
Stanley TS	12M42	452	1537	55811	0.008	0.028	0.294
Stanley TS	12M31	2234	1396	55811	0.040	0.025	1.600
Stanley TS	12M43	532	1067	55811	0.010	0.019	0.499
Stanley TS	12M33	1004	625	55811	0.018	0.011	1.606
Murray TS	3M52	364	567	55811	0.007	0.010	0.642
Kalar TS	KM5	169	549	55811	0.003	0.010	0.307
Stanley TS	12M32	1468	507	55811	0.026	0.009	2.896
Stanley TS	12M5	437	386	55811	0.008	0.007	1.133
Stanley TS	12M1	1182	376	55811	0.021	0.007	3.145
Niagara West TS	2508M4	307	359	55811	0.006	0.006	0.856
Murray TS	3M14	440	288	55811	0.008	0.005	1.529
Murray TS	3M16	375	253	55811	0.007	0.005	1.484
Stanley TS	12M4	15	224	55811	0.000	0.004	0.067
Beamsville TS	18M1	618	215	55811	0.011	0.004	2.876
Kalar TS	KM7	112	120	55811	0.002	0.002	0.937
Murray TS	3M15	62	111	55811	0.001	0.002	0.559
Murray TS	3M54	142	64	55811	0.003	0.001	2.217
Beamsville TS	18M3	163	46	55811	0.003	0.001	3.536
Murray TS	3M26	117	45	55811	0.002	0.001	2.601
Kalar TS	KM1	83	38	55811	0.001	0.001	2.171
Kalar TS	KM8	2	20	55811	0.000	0.000	0.081
Murray TS	3M28	61	17	55811	0.001	0.000	3.580
Murray TS	3M53	22	16	55811	0.000	0.000	1.359
Kalar TS	KM2	11	12	55811	0.000	0.000	0.942

	Lowest Level of Feeder Performance
	Highest Level of Feeder Performance

2018 Feeder Performance Summary
Sorted by SAIDI

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Vineland DS	4501F2	19769	7478	55811	0.354	0.134	2.644
Beamsville TS	18M2	12636	4635	55811	0.226	0.083	2.726
Niagara West TS	2508M5	12013	3684	55811	0.215	0.066	3.261
Murray TS	3M51	11418	8759	55811	0.205	0.157	1.304
Vineland DS	4501F1	10154	10096	55811	0.182	0.181	1.006
Niagara West TS	2508M2	8681	14932	55811	0.156	0.268	0.581
Murray TS	3M17	8204	13534	55811	0.147	0.242	0.606
Beamsville TS	18M4	8106	5174	55811	0.145	0.093	1.567
Allanburg TS	45M7	6595	3823	55811	0.118	0.068	1.725
Kalar TS	KM6	5272	3446	55811	0.094	0.062	1.530
Stanley TS	12M41	4421	2599	55811	0.079	0.047	1.701
Murray TS	3M27	3719	4393	55811	0.067	0.079	0.847
Kalar TS	KM3	2754	3226	55811	0.049	0.058	0.854
Murray TS	3M30	2496	4734	55811	0.045	0.085	0.527
Stanley TS	12M31	2234	1396	55811	0.040	0.025	1.600
Murray TS	3M56	1916	2969	55811	0.034	0.053	0.645
Stanley TS	12M32	1468	507	55811	0.026	0.009	2.896
Stanley TS	12M1	1182	376	55811	0.021	0.007	3.145
Stanley TS	12M33	1004	625	55811	0.018	0.011	1.606
Stanley TS	12M6	943	2736	55811	0.017	0.049	0.345
Kalar TS	KM4	677	3024	55811	0.012	0.054	0.224
Beamsville TS	18M1	618	215	55811	0.011	0.004	2.876
Stanley TS	12M43	532	1067	55811	0.010	0.019	0.499
Stanley TS	12M42	452	1537	55811	0.008	0.028	0.294
Murray TS	3M14	440	288	55811	0.008	0.005	1.529
Stanley TS	12M5	437	386	55811	0.008	0.007	1.133
Murray TS	3M16	375	253	55811	0.007	0.005	1.484
Murray TS	3M52	364	567	55811	0.007	0.010	0.642
Niagara West TS	2508M4	307	359	55811	0.006	0.006	0.856
Kalar TS	KM5	169	549	55811	0.003	0.010	0.307
Beamsville TS	18M3	163	46	55811	0.003	0.001	3.536
Murray TS	3M54	142	64	55811	0.003	0.001	2.217
Murray TS	3M26	117	45	55811	0.002	0.001	2.601
Kalar TS	KM7	112	120	55811	0.002	0.002	0.937
Kalar TS	KM1	83	38	55811	0.001	0.001	2.171
Murray TS	3M15	62	111	55811	0.001	0.002	0.559
Murray TS	3M28	61	17	55811	0.001	0.000	3.580
Murray TS	3M53	22	16	55811	0.000	0.000	1.359
Stanley TS	12M4	15	224	55811	0.000	0.004	0.067
Kalar TS	KM2	11	12	55811	0.000	0.000	0.942
Kalar TS	KM8	2	20	55811	0.000	0.000	0.081

	Lowest Level of Feeder Performance
	Highest Level of Feeder Performance

2018 Feeder Performance Summary

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Allanburg TS	45M7	6595	3823	55811	0.118	0.068	1.725
Beamsville TS	18M4	8106	5174	55811	0.145	0.093	1.567
Beamsville TS	18M2	12636	4635	55811	0.226	0.083	2.726
Beamsville TS	18M1	618	215	55811	0.011	0.004	2.876
Beamsville TS	18M3	163	46	55811	0.003	0.001	3.536
Kalar TS	KM6	5272	3446	55811	0.094	0.062	1.530
Kalar TS	KM3	2754	3226	55811	0.049	0.058	0.854
Kalar TS	KM4	677	3024	55811	0.012	0.054	0.224
Kalar TS	KM5	169	549	55811	0.003	0.010	0.307
Kalar TS	KM7	112	120	55811	0.002	0.002	0.937
Kalar TS	KM1	83	38	55811	0.001	0.001	2.171
Kalar TS	KM8	2	20	55811	0.000	0.000	0.081
Murray TS	3M17	8204	13534	55811	0.147	0.242	0.606
Murray TS	3M51	11418	8759	55811	0.205	0.157	1.304
Murray TS	3M30	2496	4734	55811	0.045	0.085	0.527
Murray TS	3M27	3719	4393	55811	0.067	0.079	0.847
Murray TS	3M56	1916	2969	55811	0.034	0.053	0.645
Murray TS	3M52	364	567	55811	0.007	0.010	0.642
Murray TS	3M14	440	288	55811	0.008	0.005	1.529
Murray TS	3M16	375	253	55811	0.007	0.005	1.484
Murray TS	3M15	62	111	55811	0.001	0.002	0.559
Murray TS	3M54	142	64	55811	0.003	0.001	2.217
Murray TS	3M26	117	45	55811	0.002	0.001	2.601
Murray TS	3M28	61	17	55811	0.001	0.000	3.580
Murray TS	3M53	22	16	55811	0.000	0.000	1.359
Niagara West TS	2508M2	8681	14932	55811	0.156	0.268	0.581
Niagara West TS	2508M5	12013	3684	55811	0.215	0.066	3.261
Niagara West TS	2508M4	307	359	55811	0.006	0.006	0.856
Stanley TS	12M6	943	2736	55811	0.017	0.049	0.345
Stanley TS	12M41	4421	2599	55811	0.079	0.047	1.701
Stanley TS	12M42	452	1537	55811	0.008	0.028	0.294
Stanley TS	12M31	2234	1396	55811	0.040	0.025	1.600
Stanley TS	12M43	532	1067	55811	0.010	0.019	0.499
Stanley TS	12M33	1004	625	55811	0.018	0.011	1.606
Stanley TS	12M32	1468	507	55811	0.026	0.009	2.896
Stanley TS	12M5	437	386	55811	0.008	0.007	1.133
Stanley TS	12M1	1182	376	55811	0.021	0.007	3.145
Stanley TS	12M4	15	224	55811	0.000	0.004	0.067
Vineland DS	4501F1	10154	10096	55811	0.182	0.181	1.006
Vineland DS	4501F2	19769	7478	55811	0.354	0.134	2.644

2019 Feeder Performance Summary
Sorted by SAIFI

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Niagara West TS	2508M2	20454	18605	56025	0.365	0.332	1.099
Vineland DS	4501F1	15429	13227	56025	0.275	0.236	1.166
Beamsville TS	18M1	14169	12137	56025	0.253	0.217	1.167
Beamsville TS	18M4	14122	8024	56025	0.252	0.143	1.760
Murray TS	3M51	877	5894	56025	0.016	0.105	0.149
Stanley TS	12M32	12222	5849	56025	0.218	0.104	2.090
Murray TS	3M17	5729	4334	56025	0.102	0.077	1.322
Murray TS	3M27	2327	3799	56025	0.042	0.068	0.613
Stanley TS	12M5	452	2950	56025	0.008	0.053	0.153
Beamsville TS	18M2	6113	2805	56025	0.109	0.050	2.179
Murray TS	3M30	2228	2594	56025	0.040	0.046	0.859
Allanburg TS	45M7	4250	2586	56025	0.076	0.046	1.643
Stanley TS	12M33	2082	2377	56025	0.037	0.042	0.876
Stanley TS	12M41	3325	2359	56025	0.059	0.042	1.409
Niagara West TS	2508M5	6640	1898	56025	0.119	0.034	3.499
Stanley TS	12M43	342	1850	56025	0.006	0.033	0.185
Kalar TS	KM2	1124	1723	56025	0.020	0.031	0.652
Kalar TS	KM6	4218	1570	56025	0.075	0.028	2.687
Stanley TS	12M42	970	1439	56025	0.017	0.026	0.674
Vineland DS	4501F2	2572	1262	56025	0.046	0.023	2.038
Beamsville TS	18M3	5092	1021	56025	0.091	0.018	4.987
Murray TS	3M56	1139	766	56025	0.020	0.014	1.487
Niagara West TS	2508M4	1026	562	56025	0.018	0.010	1.825
Kalar TS	KM3	1334	549	56025	0.024	0.010	2.429
Stanley TS	12M1	378	441	56025	0.007	0.008	0.856
Murray TS	3M54	454	404	56025	0.008	0.007	1.123
Stanley TS	12M6	620	283	56025	0.011	0.005	2.190
Murray TS	3M16	25	209	56025	0.000	0.004	0.119
Stanley TS	12M31	169	155	56025	0.003	0.003	1.093
Kalar TS	KM7	259	130	56025	0.005	0.002	1.993
Murray TS	3M26	123	69	56025	0.002	0.001	1.787
Kalar TS	KM4	62	69	56025	0.001	0.001	0.898
Kalar TS	KM5	102	42	56025	0.002	0.001	2.419
Stanley TS	12M4	49	40	56025	0.001	0.001	1.224
Murray TS	3M53	37	24	56025	0.001	0.000	1.534
Murray TS	3M29	3	19	56025	0.000	0.000	0.183
Kalar TS	KM8	47	15	56025	0.001	0.000	3.136
Kalar TS	KM1	13	15	56025	0.000	0.000	0.883
Murray TS	3M52	24	12	56025	0.000	0.000	2.001
Murray TS	3M28	16	8	56025	0.000	0.000	1.967
Murray TS	3M15	2	1	56025	0.000	0.000	1.550

	Lowest Level of Feeder Performance
	Highest Level of Feeder Performance

2019 Feeder Performance Summary
Sorted by SAIDI

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Niagara West TS	2508M2	20454	18605	56025	0.365	0.332	1.099
Vineland DS	4501F1	15429	13227	56025	0.275	0.236	1.166
Beamsville TS	18M1	14169	12137	56025	0.253	0.217	1.167
Beamsville TS	18M4	14122	8024	56025	0.252	0.143	1.760
Stanley TS	12M32	12222	5849	56025	0.218	0.104	2.090
Niagara West TS	2508M5	6640	1898	56025	0.119	0.034	3.499
Beamsville TS	18M2	6113	2805	56025	0.109	0.050	2.179
Murray TS	3M17	5729	4334	56025	0.102	0.077	1.322
Beamsville TS	18M3	5092	1021	56025	0.091	0.018	4.987
Allanburg TS	45M7	4250	2586	56025	0.076	0.046	1.643
Kalar TS	KM6	4218	1570	56025	0.075	0.028	2.687
Stanley TS	12M41	3325	2359	56025	0.059	0.042	1.409
Vineland DS	4501F2	2572	1262	56025	0.046	0.023	2.038
Murray TS	3M27	2327	3799	56025	0.042	0.068	0.613
Murray TS	3M30	2228	2594	56025	0.040	0.046	0.859
Stanley TS	12M33	2082	2377	56025	0.037	0.042	0.876
Kalar TS	KM3	1334	549	56025	0.024	0.010	2.429
Murray TS	3M56	1139	766	56025	0.020	0.014	1.487
Kalar TS	KM2	1124	1723	56025	0.020	0.031	0.652
Niagara West TS	2508M4	1026	562	56025	0.018	0.010	1.825
Stanley TS	12M42	970	1439	56025	0.017	0.026	0.674
Murray TS	3M51	877	5894	56025	0.016	0.105	0.149
Stanley TS	12M6	620	283	56025	0.011	0.005	2.190
Murray TS	3M54	454	404	56025	0.008	0.007	1.123
Stanley TS	12M5	452	2950	56025	0.008	0.053	0.153
Stanley TS	12M1	378	441	56025	0.007	0.008	0.856
Stanley TS	12M43	342	1850	56025	0.006	0.033	0.185
Kalar TS	KM7	259	130	56025	0.005	0.002	1.993
Stanley TS	12M31	169	155	56025	0.003	0.003	1.093
Murray TS	3M26	123	69	56025	0.002	0.001	1.787
Kalar TS	KM5	102	42	56025	0.002	0.001	2.419
Kalar TS	KM4	62	69	56025	0.001	0.001	0.898
Stanley TS	12M4	49	40	56025	0.001	0.001	1.224
Kalar TS	KM8	47	15	56025	0.001	0.000	3.136
Murray TS	3M53	37	24	56025	0.001	0.000	1.534
Murray TS	3M16	25	209	56025	0.000	0.004	0.119
Murray TS	3M52	24	12	56025	0.000	0.000	2.001
Murray TS	3M28	16	8	56025	0.000	0.000	1.967
Kalar TS	KM1	13	15	56025	0.000	0.000	0.883
Murray TS	3M29	3	19	56025	0.000	0.000	0.183
Murray TS	3M15	2	1	56025	0.000	0.000	1.550

	Lowest Level of Feeder Performance
	Highest Level of Feeder Performance

2019 Feeder Performance Summary

Substation Name	Feeder ID	Total Customer Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Average Hours of Interruptions / Customers (4) = (1) / (3)	SAIFI Average # of Interruptions / Customers (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Allanburg TS	45M7	4250	2586	56025	0.076	0.046	1.643
Beamsville TS	18M1	14169	12137	56025	0.253	0.217	1.167
Beamsville TS	18M4	14122	8024	56025	0.252	0.143	1.760
Beamsville TS	18M2	6113	2805	56025	0.109	0.050	2.179
Beamsville TS	18M3	5092	1021	56025	0.091	0.018	4.987
Kalar TS	KM6	4218	1570	56025	0.075	0.028	2.687
Kalar TS	KM3	1334	549	56025	0.024	0.010	2.429
Kalar TS	KM2	1124	1723	56025	0.020	0.031	0.652
Kalar TS	KM7	259	130	56025	0.005	0.002	1.993
Kalar TS	KM5	102	42	56025	0.002	0.001	2.419
Kalar TS	KM4	62	69	56025	0.001	0.001	0.898
Kalar TS	KM8	47	15	56025	0.001	0.000	3.136
Kalar TS	KM1	13	15	56025	0.000	0.000	0.883
Murray TS	3M17	5729	4334	56025	0.102	0.077	1.322
Murray TS	3M27	2327	3799	56025	0.042	0.068	0.613
Murray TS	3M30	2228	2594	56025	0.040	0.046	0.859
Murray TS	3M56	1139	766	56025	0.020	0.014	1.487
Murray TS	3M51	877	5894	56025	0.016	0.105	0.149
Murray TS	3M54	454	404	56025	0.008	0.007	1.123
Murray TS	3M26	123	69	56025	0.002	0.001	1.787
Murray TS	3M53	37	24	56025	0.001	0.000	1.534
Murray TS	3M16	25	209	56025	0.000	0.004	0.119
Murray TS	3M52	24	12	56025	0.000	0.000	2.001
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Murray TS	3M15	2	1	56025	0.000	0.000	1.550
Niagara West TS	2508M2	20454	18605	56025	0.365	0.332	1.099
Niagara West TS	2508M5	6640	1898	56025	0.119	0.034	3.499
Niagara West TS	2508M4	1026	562	56025	0.018	0.010	1.825
Stanley TS	12M32	12222	5849	56025	0.218	0.104	2.090
Stanley TS	12M41	3325	2359	56025	0.059	0.042	1.409
Stanley TS	12M33	2082	2377	56025	0.037	0.042	0.876
Stanley TS	12M42	970	1439	56025	0.017	0.026	0.674
Stanley TS	12M6	620	283	56025	0.011	0.005	2.190
Stanley TS	12M5	452	2950	56025	0.008	0.053	0.153
Stanley TS	12M1	378	441	56025	0.007	0.008	0.856
Stanley TS	12M43	342	1850	56025	0.006	0.033	0.185
Stanley TS	12M31	169	155	56025	0.003	0.003	1.093
Stanley TS	12M4	49	40	56025	0.001	0.001	1.224
Vineland DS	4501F1	15429	13227	56025	0.275	0.236	1.166
Vineland DS	4501F2	2572	1262	56025	0.046	0.023	2.038

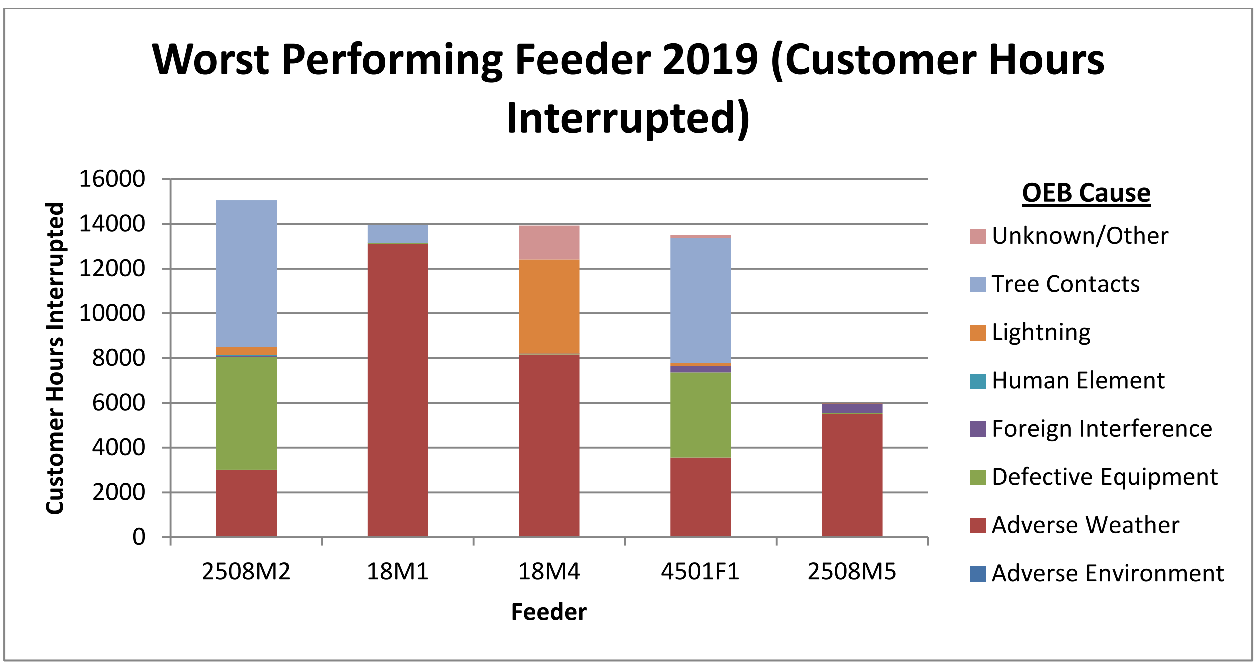
Previous Year's Worst Five Feeder Performance

The following tables and charts summarize the worst five feeders for 2019 based on Customer Hours Interrupted (CHI), and number of Customers Interrupted (CI).

Worst Five Performing Feeders by Customer Hours Interrupted (CHI)

Feeder	Number of Outages	SAIDI	SAIFI	CHI	Customers Interrupted
2508M2	112	0.26860	0.22931	15,049	12,847
4501F1	65	0.24081	0.21678	13,492	12,145
18M1	22	0.24903	0.21030	13,952	11,782
18M4	18	0.24851	0.13703	13,923	7,677
2508M5	13	0.10704	0.02515	5,997	1,409
Grand Total	**230**	**1.11400**	**0.81856**	**62,412**	**45,860**

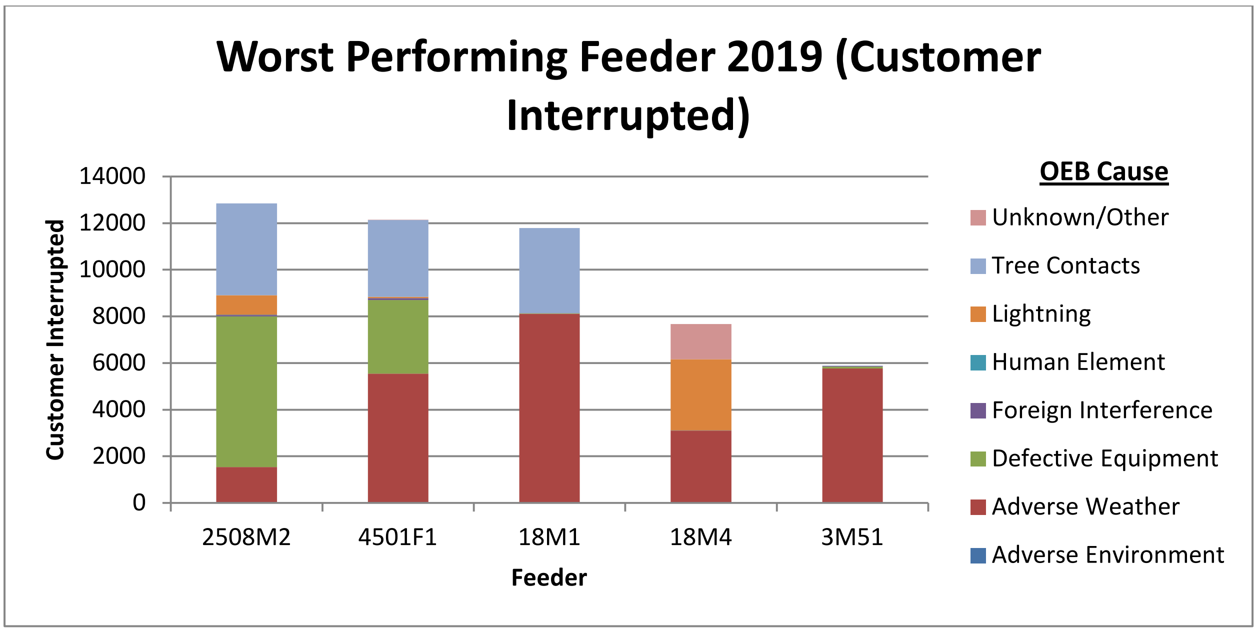
*Red feeders overlap in CHI and CI



Worst Five Performing Feeders by Customers Interrupted (CI)

Feeder	Number of Outages	SAIDI	SAIFI	CHI	Customers Interrupted
2508M2	112	0.26860	0.22931	15,049	12,847
4501F1	65	0.24081	0.21678	13,492	12,145
18M1	22	0.24903	0.21030	13,952	11,782
18M4	18	0.24851	0.13703	13,923	7,677
3M51	18	0.01541	0.10490	863	5,877
Grand Total	**235**	**1.02237**	**0.89831**	**57,278**	**50,328**

***Red feeders overlap in CHI and CI**



Feeder Analysis

As seen in the Tables above, there are four (4) feeders, highlighted in red, that appear on both lists of WPF. Feeders 2508M2, 4501F1, 18M1, and 18M4 appear on both lists. The following is a brief analysis of the main driver(s) for these feeders contributing significant outage minutes to overall system reliability.

2508M2 (Niagara West TS)

This feeder is a mix of rural and urban, servicing the majority of the rural portion of the Town of West Lincoln and the urban portion of Smithville. Approximately 3,296 customers are supplied by the 2508M2. The main causes for outages on this feeder during the previous year were Adverse Weather, Tree Contact and Defective Equipment. The majority of equipment problems related to either failed porcelain insulated switches and blown fuses. NPEI has experienced issues with older porcelain cutouts in that they tend to track and flash over resulting in outages during light rain, icy or foggy conditions. NPEI crews have standing directions to replace older porcelain cutouts with new polymeric cutouts whenever they are responding to a trouble call or service upgrade etc, involving these devices. Many of the blown fuse and tree contact events also correspond to adverse weather events involving wind, ice or lightening.

The majority of the area serviced by the 2508M2 feeder was included in the tree trimming cycle for 2019 which was completed near the end of 2019. NPEI will continue to monitor feeder performance in 2020 as the tree trimming operations may have resolved many of the potential causes.

A review of lightening arrester installations is to be undertaken in 2020 and additional lightening arresters installed as required.

4501F1 (Vineland DS)

This feeder is a mix of urban and rural serving approximately 2,200 customers in and around the town of Vineland in Lincoln. The main causes for outages on this feeder during the previous year were Adverse Weather, Defective Equipment and Tree Contacts. The majority of equipment problems related to either failed porcelain insulated switches and blown fuses. NPEI has experienced issues with older porcelain cutouts in that they tend to track and flash over resulting in outages during light rain, icy or foggy conditions. NPEI crews have standing directions to replace older porcelain cutouts with new polymeric cutouts whenever they are responding to a trouble call or service upgrade etc, involving these devices. Many of the blown fuse and tree contact events also correspond to adverse weather events involving wind, ice or lightening.

The area serviced by the 4501F1 feeder was included in the tree trimming cycle for 2017. NPEI to monitor feeder performance in 2020 as the tree trimming operations may need to be adjusted for more aggressive growth rates if tree contact issues continue increasing in 2020.

A review of lightening arrester installations is to be undertaken in 2020 and additional lightening arresters installed as required.

18M1 (Beamsville TS)

This feeder is mostly residential, servicing approximately 3,920 customers in the town of Beamsville in West Lincoln. The main cause for outages on this feeder during the previous year was Adverse Weather. Specifically, there were two high wind events and one freezing rain event. On December 1, 2019 there was a Freezing Rain event in the Niagara Region that caused the 2508M5 Feeder Breaker to open. This event affected 3,910 customers for 178 minutes, this event alone equated to 11,614 CHI or 83% of the total Customer Hour Interruptions. The majority of equipment problems related to either failed porcelain insulated switches and blown fuses and arresters. NPEI has experienced issues with older porcelain cutouts in that they tend to track and flash over resulting in outages during light rain, icy or foggy conditions. NPEI crews have standing directions to replace older porcelain cutouts with new polymeric cutouts whenever they are responding to a trouble call or service upgrade etc, involving these devices.

A review of lightening arrester installations is to be undertaken in 2020 and additional lightening arresters installed as required.

18M4 (Beamsville TS)

This feeder is mostly residential, servicing approximately 1,600 customers in the town of Beamsville in West Lincoln. The main causes for outages on this feeder during the previous year were Adverse Weather, Lightening and defective Equipment. Specifically, there were two high wind events and one freezing rain event. The majority of equipment problems related to either failed porcelain insulated switches and blown fuses and arresters. NPEI has experienced issues with older porcelain cutouts in that they tend to track and flash over resulting in outages during light rain, icy or foggy conditions. NPEI crews have standing directions to replace older porcelain cutouts with new polymeric cutouts whenever they are responding to a trouble call or service upgrade etc, involving these devices.

A review of lightening arrester installations is to be undertaken in 2020 and additional lightening arresters installed as required.

<u>Remaining two worst performing feeders:</u>

The two remaining worst performing feeders are the 2508M5 and the 3M51. The following is a brief analysis of the main driver(s) for these feeders contributing significant outage minutes to overall system reliability.

2508M5 (Niagara West TS)

This feeder is mostly farm and residential serving approximately 1,300 mostly rural customers in the North end of West Lincoln. The main causes for outages on this feeder during the previous year were Adverse Weather and Foreign Interference. On December 1, 2019 there was a Freezing Rain event in the Niagara Region that caused the 2508M5 Feeder Breaker to open. This event affected 1,293 customers for 255 minutes, this event alone equated to 5,515 Customer Hour Interruptions or 92% of the total Customer Hour Interruptions for the year 2019 on this feeder.

3M51 (Murray TS)

This feeder is mix of residential and commercial loads, servicing approximately 2,900 urban customers in the city of Niagara Falls. The main causes for outages on this feeder during the previous year were Adverse Weather. Specifically on February 24, 2019 there was a High Wind Event that caused the Feeder Breaker to open twice in the same day. These two events affected 2,858 customers twice equating to 5,716 Customer Interruptions or 5,877 or 97% of the total Customer Interruptions for the year 2019 on this feeder.

Appendix I:
NPEI’s OEB Scorecard

Scorecard - Niagara Peninsula Energy Inc.

8/14/2019

Performance Outcomes	Performance Categories	Measures		2014	2015	2016	2017	2018	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		91.00%	91.40%	92.70%	91.48%	93.33%	up	90.00%	
		Scheduled Appointments Met On Time		95.10%	95.70%	99.80%	98.34%	98.89%	up	90.00%	
		Telephone Calls Answered On Time		81.60%	82.70%	83.00%	87.99%	85.87%	up	65.00%	
	Customer Satisfaction	First Contact Resolution		93%	94%	94%	92%	91%			
		Billing Accuracy		99.58%	99.28%	99.74%	99.46%	99.06%	down	98.00%	
		Customer Satisfaction Survey Results		87%	87%	86%	86%	95%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness			84.00%	84.00%	83.00%	83.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	flat		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	flat		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		3.69	2.05	1.52	1.37	1.98	down		2.58
		Average Number of Times that Power to a Customer is Interrupted [2]		1.51	1.42	1.38	1.55	1.65	up		1.30
	Asset Management	Distribution System Plan Implementation Progress		95.2%	94.55%	95.97%	100.69%	99.27%			
	Cost Control	Efficiency Assessment		3	3	3	3	3			
		Total Cost per Customer [3]		$742	$744	$747	$741	$755			
		Total Cost per Km of Line [3]		$19,458	$19,871	$19,980	$20,285	$20,745			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]			17.12%	34.03%	58.78%	72.00%			74.44 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			100.00%	66.67%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%	100.00%	flat	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.86	1.90	1.84	1.59	1.44			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.89	0.82	1.01	0.97	0.92			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.58%	9.30%	9.30%	9.30%	9.30%			
			Achieved	4.89%	8.96%	6.86%	3.57%	5.03%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend:
5-year trend: up, down, flat
Current year: target met, target not met

Appendix J:
OEB Chapter 5 – Appendix 5-A

File Number:	
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 5-A
Metrics

Metric Category	Metric	Measures	
		1 Year	5 Year Average
Cost	Total Cost per Customer[1]	590.6160834	567.4122164
	Total Cost per km of Line[2]	16184.7859	15401.95867
	Total Cost per MW[3]	131876.0332	121636.2833
CAPEX	Total CAPEX per Customer	456.3903868	439.7150212
	Total CAPEX per km of Line	12506.56883	11934.76428
O&M	Total O&M per Customer	134.2256966	127.6971952
	Total O&M per km of Line	3678.217073	3467.194386

Notes to the Table:

1 The Total Cost per Customer is the sum of a distributor's capital and O&M costs divided by the total number of customers that the distributor serves.
2 The Total Cost per km of Line is the sum of a distributor's capital and O&M costs divided by the total number of kilometers of line that the distributor
3 The Total Cost per MW is the sum of the distributor's capital and O&M costs divided by the total peak MW that the distributor serves.

Explanatory Notes on Adverse Deviations (complete only if applicable)

Metric Name:

Metric Name:

Metric Name: