Daliana Coban
Director, Regulatory Applications & Business Support
Toronto Hydro-Electric System Limited
14 Carlton Street | Toronto, Ontario, M5B 1K5
Visit us at: www.torontohydro.com
Email: regulatoryaffairs@torontohydro.com

via Regulatory Electronic Submission System (RESS)

January 29, 2024

Ms. Nancy Marconi, Registrar
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: OEB File No. EB-2023-0195, Toronto Hydro-Electric System Limited ("Toronto Hydro") 2025-2029 Custom Rate Application for Electricity Distribution Rates and Charges – Evidence Update

Toronto Hydro is filing an update to the System Peak Demand Forecast in Exhibit 2B, Section D4 along with updates to the following programs that relate to the System Peak Demand Forecast: i) Station Expansion (Exhibit 2B, Section E7.4); ii) Load Demand (Exhibit 2B, Section E5.3) and iii) Non-Wires Solutions (Exhibit 2B, Section E7.2). In addition, Toronto Hydro flowed through capital expenditure plan updates to the Rate Base evidence in Exhibit 2A. Appendix A to this letter provides a detailed summary of the revised evidence. The financial impact of the updates is as follows:

- reduced the 2025-2029 capital expenditure plan by approximately $68 million;
- reclassified approximately $15 million to 2026-2029 Renewable Enabling Investments (REI);
- reduced the 2025-2029 forecasted in-service additions by approximately $33 million.

Toronto Hydro expects that this update will also have a minor, but not immaterial, impact on the Load Forecast in Exhibit 3, the depreciation schedules, PILs and Revenue Requirement models in Exhibit 6, and the calculation of the Performance Incentive in Exhibit 1B which is a function of the utility's Revenue Requirement. In the interest of timeliness and efficiency in updating the application record, these updates will be processed and filed along with 2023 actuals before the Technical Conference (TC) so that parties have an opportunity to ask any clarifying questions at the TC.

Please do not hesitate to contact us if you have any questions.

Sincerely,

Daliana Coban
Director, Regulatory Applications & Business Support
Toronto Hydro-Electric System Limited

Cc: Charles Keizer and Arlen Sternberg, Torys LLP; all intervenors

Appendix A: Summary of Updated Evidence (January 29, 2024)

Original Evidence (filed November 17, 2023)	Revised Evidence (filed January 29, 2024)	Summary of Numeric Differences
Rate Base Overview **(Exhibit 2A, Tab 1, Sch 1)**	Revised the Gross and Net Property, Plant and Equipment ("PP&E") to reflect the capital expenditure plan changes noted in the cover letter.	**Table 2: 2025 Rate Base Summary ($ Millions)** **Table 5: 2025-2029 Gross and Net PP&E – Years Ending December 31 ($ Millions)**
OEB Appendix 2-BA: Fixed Asset Continuity Schedule – MIFRS **(Exhibit 2A, Tab 1, Sch 2)**	Revised the Fixed Asset Continuity Schedules to reflect the capital expenditure plan changes noted in the cover letter.	

Table 2: 2025 Rate Base Summary ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Opening PP&E NBV	5,578.8	~~5,937.9~~ 5,934.5	~~6,335.2~~ 6,325.6	~~6,809.6~~ 6,794.1	~~7,234.4~~ 7,219.0
In-Service Additions	~~645.9~~ 642.1	~~699.4~~ 691.7	~~795.6~~ 789.8	769.2	~~875.4~~ 859.5
Depreciation	(286.3)	~~(301.4)~~ (300.6)	~~(321.9)~~ (321.4)	(344.3)	~~(357.1)~~ (356.5)
Closing PP&E NBV	~~5,937.9~~ 5,934.5	~~6,335.9~~ 6,325.6	~~6,809.6~~ 6,794.1	~~7,234.4~~ 7,219.0	~~7,752.7~~ 7,722.0
Monthly Avg PP&E NBV	**~~5,669.8~~ 5,668.6**	**~~6,047.4~~ 6,041.6**	**~~6,472.2~~ 6,460.1**	**~~6,927.1~~ 6,911.7**	**~~7,352.5~~ 7,335.2**
Working Capital Allowance	231.5	237.1	242.5	250.8	255.6
Rate Base	**~~5,901.2~~ 5,900.0**	**~~6,284.5~~ 6,278.7**	**~~6,714.7~~ 6,702.6**	**~~7,177.9~~ 7,162.5**	**~~7,608.2~~ 7,590.8**

Table 5: 2025-2029 Gross and Net PP&E – Years Ending December 31 ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Land and Buildings	237.7	249.1	268.4	279.9	302.3
Other Distribution Assets	877.7	940.3	1,036.6	1,102.5	~~1,225.1~~ 1,210.3
General Plant	338.7	358.0	382.8	413.1	459.1
TS Primary Above 50	81.3	80.5	79.8	79.0	78.3
Distribution System	~~368.5~~ 368.4	~~408.1~~ 407.9	~~455.6~~ 455.3	~~492.5~~ 492.3	~~524.2~~ 523.9
Poles, Wires	~~5,426.7~~ 5,423.6	~~5,906.2~~ 5,896.6	~~6,400.8~~ 6,385.9	~~6,934.5~~ 6,919.3	~~7,504.3~~ 7,488.3
Contributions and Grants	(1,008.6)	(1,155.5)	(1,294.0)	(1,448.4)	~~(1,617.7)~~ (1,617.8)
Line Transformers	1,110.7	1,193.1	~~1,277.9~~	~~1,367.7~~	~~1,461.5~~

Original Evidence (filed November 17, 2023)	Revised Evidence (filed January 29, 2024)	Summary of Numeric Differences

			1,277.7	1,367.4	1,461.2
Services and Meters	526.6	~~584.7~~ 584.8	647.6	~~698.9~~ 699.0	733.9
Equipment	286.7	307.3	~~325.2~~ 325.1	~~345.2~~ 345.1	370.6
IT Assets	176.1	195.8	226.7	254.7	295.1
Gross Assets	**~~8,422.1~~ 8,418.8**	**~~9,067.7~~ 9,057.7**	**~~9,807.2~~ 9,791.8**	**~~10,519.6~~ 10,503.9**	**~~11,336.6~~ 11,305.1**
Accumulated Depreciation	~~(2,484.2)~~ (2,484.3)	~~(2,731.8)~~ (2,732.1)	~~(2,997.7)~~ (2,997.8)	~~(3,285.2)~~ (3,284.9)	~~(3,583.9)~~ (3,583.2)
Closing PP&E NBV	**~~5,937.9~~ 5,934.5**	**~~6,335.9~~ 6,325.6**	**~~6,809.6~~ 6,794.1**	**~~7,234.4~~ 7,219.0**	**~~7,752.7~~ 7,722.0**

Table 10: 2024 Bridge versus 2025 Forecast PP&E NBV ($ Millions)

	2024 Bridge	2025 Forecast	Variance ($)	Variance (%)
Land and Buildings	229.9	237.7	7.8	3.4%
Other Distribution Assets	815.8	877.7	61.9	7.6%
General Plant	327.9	338.7	10.8	3.3%
TS Primary Above 50	82.1	81.3	(0.8)	-0.9%
Distribution System	332.9	~~368.5~~ 368.4	35.6	10.7%
Poles, Wires	5,017.8	~~5,426.7~~ 5,423.6	~~408.9~~ 405.8	8.1%
Contributions and Grants	(898.8)	(1,008.6)	(109.9)	12.2%
Line Transformers	1,027.2	1,110.7	83.5	8.1%
Services and Meters	476.5	526.6	50.1	10.5%
Equipment	262.1	286.7	24.6	9.4%
IT Assets	154.6	176.1	21.5	13.9%
Gross Assets	**7,827.9**	**~~8,422.1~~ 8,418.8**	**~~594.1~~ 590.9**	**~~7.6%~~ 7.5%**
Accumulated Depreciation	(2,249.2)	~~(2,484.2)~~ (2,484.3)	~~(235.0)~~ (235.2)	10.5%
Closing PP&E NBV	**5,578.8**	**~~5,937.9~~ 5,934.5**	**~~359.1~~ 355.7**	**6.4%**

<table>
<tr><th>Original Evidence
(filed November 17, 2023)</th><th>Revised Evidence
(filed January 29, 2024)</th><th>Summary of Numeric Differences</th></tr>
<tr><td></td><td></td><td>

Table 11: 2025 Forecast versus 2029 Forecast ($ Millions)

	2025 Forecast	2029 Forecast	Variance ($)	Variance (%)
Land and Buildings	237.7	302.3	64.7	27.2%
Other Distribution Assets	877.7	~~1,225.1~~ 1,210.3	~~347.4~~ 332.6	~~39.6%~~ 37.9%
General Plant	338.7	459.1	120.4	35.5%
TS Primary Above 50	81.3	78.3	(3.0)	-3.7%
Distribution System	~~368.5~~ 368.4	~~524.2~~ 523.9	~~155.7~~ 155.5	~~42.3%~~ 42.2%
Poles, Wires	~~5,426.7~~ 5,423.6	~~7,504.3~~ 7,488.3	~~2,077.5~~ 2,064.6	~~38.3%~~ 38.1%
Contributions and Grants	(1,008.6)	~~(1,617.7)~~ (1,617.8)	(609.1)	60.4%
Line Transformers	1,110.7	~~1,461.5~~ 1,461.2	~~350.8~~ 350.5	31.6%
Services and Meters	526.6	733.9	207.3	39.4%
Equipment	286.7	370.6	~~83.9~~ 83.8	29.2%
IT Assets	176.1	295.1	119.0	67.6%
Gross Assets	**~~8,422.1~~ 8,418.8**	**~~11,336.6~~ 11,305.1**	**~~2,914.5~~ 2,886.3**	**~~34.6%~~ 34.3%**
Accumulated Depreciation	~~(2,484.2)~~ (2,484.3)	~~(3,583.9)~~ (3,583.2)	~~(1,099.7)~~ (1,098.8)	~~44.3%~~ 44.2%
Closing PP&E NBV	**~~5,937.9~~ 5,934.5**	**~~7,752.7~~ 7,722.0**	**~~1,814.8~~ 1,787.5**	**~~30.6%~~ 30.1%**

</td></tr>
<tr><td>

Depreciation and Amortization

(Exhibit 2A, Tab 2, Sch 1)

Summary of Depreciation Expense

(Exhibit 2A, Tab 2, Sch 1, App A)

</td><td>Revised the Summary of Depreciation Expense to reflect the capital expenditure plan changed noted in the cover letter.</td><td>

Table 8: Depreciation and Amortization Expense 2025 to 2029 ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Depreciation and Amortization Expense	247.4	~~260.3~~ 260.1	~~278.8~~ 278.5	~~300.4~~ 300.1	~~311.7~~ 311.2

</td></tr>
</table>

<table>
<tr><th>Original Evidence
(filed November 17, 2023)</th><th>Revised Evidence
(filed January 29, 2024)</th><th>Summary of Numeric Differences</th></tr>
<tr><td>Derecognition

(Exhibit 2A, Tab 2, Sch 2)</td><td>Revised the Derecognition expense to reflect the capital expenditure plan changes noted in the cover letter.</td><td>Table 2: 2025-2029 Derecognition ($ Millions)
<table>
<tr><th></th><th>2025</th><th>2026</th><th>2027</th><th>2028</th><th>2029</th></tr>
<tr><td>Derecognition</td><td>~~37.9~~
37.5</td><td>~~39.4~~
38.7</td><td>~~41.1~~
40.8</td><td>~~41.6~~
41.9</td><td>~~42.8~~
42.6</td></tr>
</table></td></tr>
<tr><td>Eligible Investments

(Exhibit 2A, Tab 5, Sch 1)</td><td rowspan="2">Added a new section re eligible stations expansions investments at Sheppard TS for which Toronto Hydro is seeking provincial rate protection.</td><td rowspan="2">Table 1: Renewable Enabling Improvements (“REI”) from 2025-2029 ($ Millions)
<table>
<tr><th>Capital Program</th><th>2025</th><th>2026</th><th>2027</th><th>2028</th><th>2029</th><th>Total</th></tr>
<tr><td>Generation, Protection, Monitoring, and Control</td><td>5.9</td><td>6.1</td><td>6.3</td><td>6.5</td><td>10.3</td><td>35.0</td></tr>
<tr><td>Energy Storage</td><td>3.6</td><td>3.6</td><td>7.5</td><td>3.8</td><td>4.0</td><td>22.5</td></tr>
<tr><td>Stations Expansion – Sheppard TS Bus Expansion</td><td>-</td><td>0.5</td><td>4.5</td><td>5.0</td><td>5.0</td><td>15.0</td></tr>
<tr><td>Totals</td><td>9.5</td><td>~~9.7~~
10.2</td><td>~~13.8~~
18.3</td><td>~~10.3~~
15.3</td><td>~~14.3~~
19.3</td><td>~~57.5~~
72.5</td></tr>
</table></td></tr>
<tr><td>OEB Appendix 2-FA/2-FB – Stations Expansion

(*NEW Exhibit 2A, Tab 5, Sch. 5-6)</td></tr>
<tr><td>Capacity Planning and Electrification

(Exhibit 2B, Section D4)</td><td>Revised graphs and narrative to reflect the 2023 System Peak Demand Forecast and the capital expenditure plan changes noted in the cover letter.</td><td>N/A</td></tr>
<tr><td>Capability for Renewables

(Exhibit 2B, Section E3)</td><td>Added a new section re stations expansions investments at Sheppard TS to enable DER connections.</td><td>N/A</td></tr>
</table>

Original Evidence (filed November 17, 2023)	Revised Evidence (filed January 29, 2024)	Summary of Numeric Differences
Capital Expenditure Summary **(Exhibit 2B, Section E4)**	Revised tables to account for the capital expenditure plan changes noted in the cover letter. Revised sentence re Hydro One capital contribution for Sheppard TS expansion	Note 2020-2024 actuals bridge were removed due to table size.

Table 4: Historical and Forecast Share of Total by Investment Category

Category	Forecast Share of Total (%)					
	2025	2026	2027	2028	2029	Avg.
System Access	~~31%~~ 30%	~~31%~~ 30%	~~27%~~ 28%	~~23%~~ 24%	23%	**27%**
System Renewal	~~49%~~ 49%	48%	~~47%~~ 48%	~~50%~~ 51%	53%	~~**49%**~~ **50%**
System Service	~~6%~~ 5%	5%	~~10%~~ 8%	~~12%~~ 9%	~~11%~~ 10%	~~**9%**~~ **8%**
General Plant	14%	16%	~~15%~~ 15%	14%	~~12%~~ 12%	~~**14%**~~ **14%**
Other CAPEX	1%	1%	1%	1%	1%	**1%**
Total	100%	100%	100%	100%	100%	**100%**

Table 5: System Access: 2020-2029 Expenditures ($ Millions)

	Forecast				
	2025	2026	2027	2028	2029
System Access	~~226.5~~ 220.1	~~239.3~~ 229.1	~~228.3~~ 224.0	~~192.8~~ 196.6	~~184.8~~ 182.7

Table 7: System Service Expenditures: 2020-2029 ($ Millions)

	Forecast				
	2025	2026	2027	2028	2029
System Service	38.3	35.0	~~83.0~~ 66.0	~~95.1~~ 78.1	~~101.2~~ 84.3

Table 11: Forecasted 2025-2029 CWIP ($ Millions)

	Forecast				
	2025	2026	2027	2028	2029
Opening CWIP	456.4	~~536.3~~ 533.7	~~595.1~~ 589.1	~~622.7~~ 596.4	~~681.7~~ 636.6
Additions (CAPEX)	~~725.8~~ 719.4	~~758.1~~ 747.1	~~823.2~~ 797.2	~~828.2~~ 809.3	~~812.3~~ 786.7

<table>
<tr><th>Original Evidence
(filed November 17, 2023)</th><th>Revised Evidence
(filed January 29, 2024)</th><th>Summary of Numeric Differences</th></tr>
<tr><td></td><td></td><td>
<table>
<tr><td>Deductions (In Service Additions)</td><td>~~(645.9)~~ (642.1)</td><td>~~(699.4)~~ (691.7)</td><td>~~795.6)~~ (789.8)</td><td>(769.2)</td><td>~~(875.4)~~(859.5)</td></tr>
<tr><td>Closing CWIP</td><td>~~536.3~~ 533.7</td><td>~~595.1~~ 589.1</td><td>~~622.7~~ 596.4</td><td>~~681.7~~ 636.6</td><td>~~618.6~~ 563.8</td></tr>
</table>
</td></tr>
<tr><td>OEB Appendix 2-AB

(Exhibit 2B, Section E4, App A)

OEB Appendix 2-AA

(Exhibit 2B, Section E4, App B)</td><td>Revised forecast expenditures at the OEB Investment Category level and Program level to reflect the capital expenditure plan changes noted in the cover letter.</td><td>
<table>
<tr><th></th><th colspan="5">Forecast</th></tr>
<tr><th></th><th>2025</th><th>2026</th><th>2027</th><th>2028</th><th>2029</th></tr>
<tr><td>Load Demand</td><td>~~50.0~~ 43.5</td><td>~~56.7~~ 46.4</td><td>~~42.3~~ 38.1</td><td>~~38.8~~ 42.7</td><td>~~48.6~~ 46.4</td></tr>
<tr><td>Stations Expansion</td><td>11.0</td><td>~~8.1~~ 7.9</td><td>~~39.2~~ 22.2</td><td>~~57.7~~ 40.7</td><td>~~57.2~~ 40.2</td></tr>
</table>

See above tables for OEB Investment Category updates.</td></tr>
<tr><td>Load Demand

(Exhibit 2B, Section E5.3)</td><td>Revised to reflect the updated 2023 Station Load forecast and revised investment plan.</td><td>Forecast 2025-2029 expenditures: ~~$236.3~~ $217.1 million.

Horseshoe: reduced number of highly loaded feeders by 2029 from 119 to 111 and the number Toronto Hydro plans to relieve over 2025-2029 from 23 to 15.

Downtown: increased number of highly loaded feeders by 2029 from 154 to 178 (from 20% to 27% of downtown feeders) and the number Toronto Hydro plans to relieve from 49 to 64.

Updated Table 5, removing Basin, Bathurst, Bermondsey, Bridgman, Fairbank, Rexdale, Runnymede, and Sheppard stations. Revised buses and/or load to transfer or added new stations to table as summarized below:
<table>
<tr><th>Station</th><th>Bus</th><th>Estimated Load to Transfer (MVA)</th><th>Area</th></tr>
<tr><td>Cecil (new)</td><td>A1-2CE</td><td>10 - 20</td><td>Downtown</td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th>Original Evidence
(filed November 17, 2023)</th><th>Revised Evidence
(filed January 29, 2024)</th><th>Summary of Numeric Differences</th></tr>
<tr><td></td><td></td><td>
<table>
<tr><td>**Copeland**</td><td>*A1-2CX*</td><td>~~5-15~~ 10 - 20</td><td>Downtown</td></tr>
<tr><td>**Dufferin**</td><td>*Note 1*</td><td>~~5-15~~ 4 - 14</td><td>Downtown</td></tr>
<tr><td>**Finch**</td><td>*~~B&Y,~~ BJ-Q*</td><td>~~25-55~~ 35 - 50</td><td>Downtown</td></tr>
<tr><td>**Leslie**</td><td>*B&Y*</td><td>~~25-40~~ 15 - 30</td><td>Horseshoe</td></tr>
<tr><td>**Manby**</td><td>*~~B&Y,~~ Q-Z*</td><td>~~20-50~~ 20 - 35</td><td>Horseshoe</td></tr>
<tr><td>**Strachan (new)**</td><td>*A9-10T*</td><td>10 - 20</td><td>Downtown</td></tr>
</table>
</td></tr>
<tr><td>**Non-Wires Solutions**

(Exhibit 2B, Section E7.2)</td><td>Revised the stations that will be targeted for demand response as part of the Flexibility Services segment.</td><td>Toronto Hydro will target ~~three~~ six stations:

~~Fairbank TS, Finch TS, and Bathurst TS~~ Finch TS, Manby TS, Leslie TS, Cecil TS, Strachan TS, and Copeland TS</td></tr>
<tr><td>**Stations Expansion**

(Exhibit 2B, Section E7.4)</td><td>Revised tables, figures, and narrative (including Appendix A re Downsview TS) to reflect updated station load forecasts. Removed evidence related to Scarborough TS Expansion (including the Business Case in Appendix B) and added narrative re Scarborough TS as part of section E7.4.8 Flexibility Considerations. Revised the narrative for the Sheppard TS expansion in section E7.4.3.2 to focus on short circuit capacity constraints to enable DERs.</td><td>Reduced Hydro One Contribution segment total 2025-2029 total forecast expenditures from $103.0 million to $51.7 million, reducing total program forecasts from $173.2 million to $121.9 million. Revised new capacity coming into service over 2030-2034 from 271 MW to 174 MW.</td></tr>
</table>

RATE BASE OVERVIEW

This schedule provides an overview of Toronto Hydro's rate base in accordance with section 2.2.1 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022) (the "Filing Requirements").

Continuity statements for Toronto Hydro's fixed assets, including interest during construction and overhead costs, are filed at Exhibit 2A, Tab 1, Schedule 2. Toronto Hydro confirms that:

- the continuity statements provide year-end balances and include interest during construction, and all overheads;
- the opening and closing balances of gross assets and accumulated depreciation that are used to calculate the fixed asset component of rate base correspond to the respective balances in the fixed asset continuity statements; and
- the continuity statements reconcile to calculated depreciation expenses (Exhibit 2A, Tab 2, Schedule 1) and are presented by asset account.

1. RATE BASE

Rate base consists of Net Book Value of PP&E (i.e. Gross Book Value minus accumulated depreciation) less Construction Work In-Progress (CWIP). Rate Base also includes a working capital allowance ("WCA") based on the cost of power and controllable expenses such as operations and maintenance, billing, collections and administration expenses.

Tables 1 and 2 below summarize Toronto Hydro's rate base values for 2020-2024 and 2025-2029 respectively, including opening and closing PP&E net book values ("NBV").

Table 1: 2020-2024 Rate Base Summary ($ Millions)

	OEB Approved	Actuals			Bridge	
	2020	2020	2021	2022	2023	2024
Opening PP&E NBV	4,229.4	4,233.2	4,419.2	4,628.1	4,893.9	5,244.3
In-Service Additions	527.4	447.9	485.2	554.4	607.9	606.3
Depreciation	(265.4)	(262.0)	(276.2)	(288.7)	(257.4)	(271.8)
Closing PP&E NBV	4,491.3	4,419.2	4,628.1	4,893.9	5,244.3	5,578.8
Monthly Avg PP&E NBV	**4,298.6**	**4,284.3**	**4,457.7**	**4,686.3**	**4,954.3**	**5,348.5**
Working Capital Allowance	216.2	249.8	217.2	220.7	221.1	230.3
Rate Base	**4,514.8**	**4,534.1**	**4,674.9**	**4,907.0**	**5,175.3**	**5,578.8**

Table 2: 2025-2029 Rate Base Summary ($ Millions)

	Forecast				
	2025	2026	2027	2028	2029
Opening PP&E NBV	5,578.8	5,934.5	6,325.6	6,794.1	7,219.0
In-Service Additions	642.1	691.7	789.8	769.2	859.5
Depreciation	(286.3)	(300.6)	(321.4)	(344.3)	(356.5)
Closing PP&E NBV	5,934.5	6,325.6	6,794.1	7,219.0	7,722.0
Monthly Avg PP&E NBV	**5,668.6**	**6,041.6**	**6,460.1**	**6,911.7**	**7,335.2**
Working Capital Allowance	231.5	237.1	242.5	250.8	255.6
Rate Base	**5,900.0**	**6,278.7**	**6,702.6**	**7,162.5**	**7,590.8**

/C

As further explained below, rate base variances are primarily driven by changes in PP&E NBV due to in-service additions derived from the capital programs in Exhibit 2B. Depreciation and Working Capital Allowance variances are discussed in Exhibit 2A, Tab 2, Schedule 1, and Exhibit 2A, Tab 3, Schedule 1, respectively.

Actual rate base in 2020 was approximately $19.2 million higher than the rate base approved by the OEB in the last rebasing application (EB-2018-0165) because of a higher than forecasted WCA ($33.5 million), offset by lower than forecasted in-service additions ($14.3 million), resulting primarily from lower expenditures in System Renewal programs.

2. IN-SERVICE ADDITIONS (ISA)

Toronto Hydro's actual ISAs are calculated in accordance with its Capitalization policy set out in Exhibit 2A, Tab 4, Schedule 1. The methodology used to forecast ISAs by asset class is consistent with the last rebasing application (EB-2018-0165).[1]

Table 3 below compares the total in-service additions included in base rates per the 2020-2024 Draft Rate Order (DRO) in EB-2018-0165, and the 2020-2024 actual and forecasted in-service additions based on the actual and forecasted expenditure levels in Exhibit 2B. In accordance with the OEB's direction in EB-2018-0165, this information is provided at the investment category level.[2] Appendix A to this schedule provides an annual breakdown of Table 3.

Table 3: 2020-2024 In-Service Additions Variances ($ Millions)

	2020-2024 DRO	2020-2024 Actual/Bridge	Var. ($)	Var. (%)
System Access	469.1	621.7	152.7	32.5%
System Renewal	1,535.8	1,407.7	(128.1)	-8.3%
System Service	259.8	270.5	10.8	4.1%
General Plant	403.7	396.6	(7.1)	-1.8%
Other	5.1	5.2	0.1	1.1%
Net In-Service Additions	**2,673.4**	**2,701.7**	**28.3**	**1.1%**

Total in-service additions for 2020-2024 are expected to be approximately $28.3 million or 1 percent higher than the in-service additions per the DRO. The key variances are as follows:

[1] In the response to Undertaking JTC3.1 in the utility's last rebasing application, Toronto Hydro noted that the methodology to forecast ISA is subject to certain limitations which may undermine the veracity of these forecasts. For example, historical conversion ratios of capital expenditures to in-service additions to the program are based on aggregate values for distribution capital, and may not be entirely aligned with program level assumptions.

[2] EB-2018-0165, Decision and Order (December 19, 2019) at page 195.

System Access related in-service additions are forecasted to be $152.7 million greater than the amounts included in base rates per the DRO primarily due to increased expenditures in demand-driven programs such as Customer Connections (Exhibit 2B, Section E5.1) and Load Demand (Exhibit 2B, Section E5.3). Toronto Hydro had to make additional investments in these programs in order to fulfil its core obligations to connect new and expanded services to the grid, including a higher than anticipated volume of system access requests for large projects (>5 MVA demand) over this period. For more details about System Access variances please refer to Exhibit 2B, Section E4.1.1.

System Service related in-service additions are forecasted to be $10.8 million greater than the amounts included in base rates per the DRO primarily due to higher expenditures in the Stations Expansion program (Exhibit 2B, Section E7.4) related to Hydro One contribution for the Horner TS expansion project. For more details about System Service variances please refer to Exhibit 2B, Section E4.1.3.

System Renewal related expenditures are forecasted to be $128.1 million lower than the amounts included in base rates per the DRO primarily due to lower expenditures in the Underground System Renewal programs (Exhibit 2B, Section E6.2 and E6.3) and Overhead System Renewal program (Exhibit 2B, Section E6.5). Toronto Hydro decided to defer expenditures in these programs in an effort to manage capital funding pressures driven by the capital stretch factor and by higher than forecasted expenditures in System Access and Service as noted above. For more details about System Renewal variances please refer to Exhibit 2B, Section E4.1.2.

General Plant related in-service additions are forecasted to be $7.1 million lower than the amounts included in base rates per the DRO primarily due to lower expenditures in the

IT/OT Systems program (Exhibit 2B, Section E8.4) related to the decision to defer the Enterprise Resource Planning (ERP) upgrade based on new information that the vendor (SAP) will continue to support the current system until 2027 with extended support available until 2030. For more details about General Plant variances please refer to Exhibit 2B, Section E4.1.4.

3. PROPERTY, PLANT AND EQUIPMENT (PP&E)

Tables 4 and 5 below present a summary of Toronto Hydro's Gross and Net PP&E, before and after accumulated depreciation, for the current 2020-2024 rate period and future 2025-2029 rate period. Toronto Hydro confirms that the PP&E net book values (NBV) reported under the Reporting and Record-keeping Requirements (RRR) are aligned with the amounts utilized for rate base purposes.[3]

Table 4: 2020-2024 Gross and Net PP&E – Years Ending December 31 ($ Millions)

	Actual			Bridge	
	2020	**2021**	**2022**	**2023**	**2024**
Land and Buildings	185.4	190.5	205.3	222.1	229.9
Other Distribution Assets	505.7	560.4	674.0	722.8	815.8
General Plant	248.1	262.5	270.0	311.6	327.9
TS Primary Above 50	40.2	40.2	37.9	75.7	82.1
Distribution System	250.9	273.6	298.6	314.5	332.9
Poles, Wires	3,475.0	3,820.4	4,185.9	4,605.8	5,017.8
Contributions and Grants	(334.7)	(459.5)	(586.0)	(745.3)	(898.8)
Line Transformers	716.0	796.4	867.2	942.2	1,027.2
Services and Meters	379.9	398.3	418.4	439.9	476.5
Equipment	166.5	184.3	204.8	239.7	262.1

[3] In past applications, the OEB approved planned investments in certain assets that meet the OEB's definition for high voltage assets. This includes qualifying assets at the Copeland TS and contributions paid to HONI for work conducted on the transmission system. Toronto Hydro also proposes investments in high voltage assets in its 2025-2029 application. Once incurred, actual costs of such assets are separately reported annually as part of RRR (section 2.1.5.2).

	Actual			Bridge	
	2020	**2021**	**2022**	**2023**	**2024**
IT Assets	94.6	110.0	121.1	138.3	154.6
Gross Assets	**5,727.5**	**6,177.1**	**6,697.2**	**7,267.3**	**7,827.9**
Accumulated Depreciation	(1,308.4)	(1,548.9)	(1,803.4)	(2,023.0)	(2,249.2)
Closing PP&E NBV	**4,419.2**	**4,628.1**	**4,893.9**	**5,244.3**	**5,578.8**

Note: Variances due to rounding may exist

Table 5: 2025-2029 Gross and Net PP&E – Years Ending December 31 ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Land and Buildings	237.7	249.1	268.4	279.9	302.3
Other Distribution Assets	877.7	940.3	1,036.6	1,102.5	1,210.3
General Plant	338.7	358.0	382.8	413.1	459.1
TS Primary Above 50	81.3	80.5	79.8	79.0	78.3
Distribution System	368.4	407.9	455.3	492.3	523.9
Poles, Wires	5,423.6	5,896.6	6,385.9	6,919.3	7,488.3
Contributions and Grants	(1,008.6)	(1,155.5)	(1,294.0)	(1,448.4)	(1,617.8)
Line Transformers	1,110.7	1,193.1	1,277.7	1,367.4	1,461.2
Services and Meters	526.6	584.8	647.6	699.0	733.9
Equipment	286.7	307.3	325.1	345.1	370.6
IT Assets	176.1	195.8	226.7	254.7	295.1
Gross Assets	**8,418.8**	**9,057.7**	**9,791.8**	**10,503.9**	**11,305.1**
Accumulated Depreciation	(2,484.3)	(2,732.1)	(2,997.8)	(3,284.9)	(3,583.2)
Closing PP&E NBV	**5,934.5**	**6,325.6**	**6,794.1**	**7,219.0**	**7,722.0**

Note: Variances due to rounding may exist

/C

3.1 2020 versus 2021 Actual

Table 6 below presents the 2020 versus 2021 actual PP&E NBV values by asset class.

Table 6: 2020 Historical versus 2021 Historical PP&E NBV ($ Millions)[4]

Asset Class	2020 Actual	2021 Actual	Variance ($)	Variance (%)
Land and Buildings	185.4	190.5	5.2	3%
Other Distribution Assets	505.7	560.4	54.7	11%
General Plant	248.1	262.5	14.5	6%
TS Primary Above 50	40.2	40.2	-	0%
Distribution System	250.9	273.6	22.7	9%
Poles, Wires	3,475.0	3,820.4	345.4	10%
Contributions and Grants	(334.7)	(459.5)	(124.8)	37%
Line Transformers	716.0	796.4	80.3	11%
Services and Meters	379.9	398.3	18.5	5%
Equipment	166.5	184.3	17.8	11%
IT Assets	94.6	110.0	15.3	16%
Gross Assets	**5,727.5**	**6,177.1**	**449.5**	**8%**
Accumulated Depreciation	(1,308.4)	(1,548.9)	(240.6)	18%
Closing PP&E NBV	**4,419.2**	**4,628.1**	**209.0**	**5%**

From 2020 to 2021, PP&E by asset class variances were as follows:

- **Land and Buildings Assets** increased by $5.2 million or 3 percent primarily due to in-service additions related to (1) Facilities Management and Security ($2.7 million) as detailed in Exhibit 2B, Section E8.2 and (2) Stations Renewal ($2.5 million) as detailed in Exhibit 2B, Section E6.6.
- **Other Distribution Assets** increased by $54.7 million or 11 percent, primarily due to (1) IT software additions ($24.4 million) as detailed in Exhibit 2B, Section E8.4 and (2) capital contributions paid to Hydro One ($18.2 million) as detailed in Exhibit 2B, Section E7.4.

[4] Further breakdown of the categories and amounts presented in Tables 3 to 7 is provided in fixed asset continuity schedules provided in Exhibit 2A, Tab 1, Schedule 2, Appendix 2-BA.

- **General Plant Assets** increased by $14.5 million or 6 percent primarily due to the in-service amounts related to Facilities Management and Security ($11.2 million) as detailed in Exhibit 2B, Section E8.2.
- **Distribution System Assets** increased by $22.7 million or 9 percent, primarily due to the completion of Stations Renewal projects ($20.9 million) as outlined Exhibit 2B, Section E6.6.
- **Poles and Wires Assets** increased by $345.4 million or 10 percent as a result of in-service additions from investments in the following programs: Customer Connections (Exhibit 2B, Section E5.1), Externally Initiated Plant Relocations & Expansions (Exhibit 2B, Section E5.2), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and the Overhead System Renewal Program (Exhibit 2B, Section E6.5). Of these programs, the largest increases were in the Customer Connections ($107.5 million) and Externally Initiated Plant Relocations & Expansions programs ($64 million) due to external factors.
- **Contributions and Grants** increased by $124.8 million or 37 percent due to customer and third-party contributions related to the Customer Connections and EIPRE programs. These contributions resulted in a reduction to NBV.
- **Line Transformers** increased by $80.3 million or 11 percent primarily from in-service additions related to Reactive and Corrective Capital program ($25.2 million) as outlined in Exhibit 2B, Section E6.7 and the Customer Connections program ($16.8 million) as outlined in Exhibit 2B, Section E5.1.
- **Services and Meter assets** increased by $18.5 million or 5 percent primarily due to the Customer Connections (Exhibit 2B, Section E5.1) and the Metering (Exhibit 2B, Section E5.4) programs.

- **Equipment Assets** increased by $17.8 million or 11 percent primarily due to investment in the Network Condition Monitoring & Control (Exhibit 2B, Section E7.3) and the Fleet and Equipment Services (Exhibit 2B, Section E8.3) programs.
- **IT assets** increased by $15.3 million or 16 percent primarily due to investment in hardware equipment within the IT/OT program (Exhibit 2B, Section E8.4).

3.2 2021 Historical versus 2022 Historical PP&E NBV

Table 7 below presents the 2020 versus 2021 actual PP&E NBV values by asset class.

Table 7: 2021 Historical versus 2022 Historical PP&E NBV ($ Millions)

	2021 Actual	2022 Actual	Variance ($)	Variance (%)
Land and Buildings	190.5	205.3	14.8	8%
Other Distribution Assets	560.4	674.0	113.6	20%
General Plant	262.5	270.0	7.5	3%
TS Primary Above 50	40.2	37.9	(2.3)	(6%)
Distribution System	273.6	298.6	25.0	9%
Poles, Wires	3,820.4	4,185.9	365.5	10%
Contributions and Grants	(459.5)	(586.0)	(126.4)	28%
Line Transformers	796.4	867.2	70.8	9%
Services and Meters	398.3	418.4	20.1	5%
Equipment	184.3	204.8	20.5	11%
IT Assets	110.0	121.1	11.1	10%
Gross Assets	**6,177.1**	**6,697.2**	**520.2**	**8%**
Accumulated Depreciation	(1,548.9)	(1,803.4)	(254.4)	16%
Closing PP&E NBV	**4,628.1**	**4,893.9**	**265.8**	**6%**

From 2021 to 2022, PP&E by asset class variances were as follows:

- **Land and Buildings Assets** increased by $14.8 million or 8 percent primarily due to investments in the Facilities Management and Security program (Exhibit 2B, Section E8.2).
- **Other Distribution Assets** increased by $113.6 million or 20 percent primarily due to capital contributions paid to Hydro One related to the expansion of Horner TS (Exhibit 2B, Section E7.4) and IT software additions (Exhibit 2B, Section E8.4).
- **General Plant Assets** increased by $7.5 million or 3 percent primarily due to the in-service amounts in the Facilities Management and Security program (Exhibit 2B, Section E8.2).
- **Distribution System Assets** increased by $25 million or 9 percent primarily due to in-service additions related to Copeland TS Phase 2 project within the Stations Expansion program (Exhibit 2B, Section E7.4).
- **Poles and Wires** increased by $365.5 million, or 10 percent, as a result of in-service additions from investments in the following programs: Customer Connections (Exhibit 2B, Section E5.1), Externally Initiated Plant Relocations & Expansion (Exhibit 2B, Section E5.2), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Load Demand (Exhibit 2B, Section E5.3), Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and the Overhead System Renewal Program (Exhibit 2B, Section E6.5). Of these programs, the largest increases were in the Customer Connections program ($99.2 million) and Externally Initiated Plant Relocations & Expansion ($80.8 million) due to external demand.
- **Contributions and grants** increased by $126.4 million or 28 percent due to customer and third-party contributions related to the Customer Connections and Externally Initiated Plant Relocations & Expansions programs. The contributions resulted in a reduction to NBV.

- **Line transformers** increased by $70.8 million or 9 percent primarily from in-service additions related to Reactive and Corrective Capital (Exhibit 2B, Section E6.7), Network System Renewal (Exhibit 2B, E6.4), Customer Connections (Exhibit 2B, Section E5.1) and Overhead System Renewal (Exhibit 2B, Section E6.5) programs.
- **Services and meter assets** increased by $20.1 million or 5 percent primarily due to the Customer Connections (Exhibit 2B, Section E5.1) and Metering (Exhibit 2B, Section E5.4) programs.
- **Equipment assets** increased by $20.5 million or 11 percent primarily due to investment in the Network Condition Monitoring & Control (Exhibit 2B, Section E7.3) and the Fleet and Equipment Services (Exhibit 2B, Section E8.3) programs.
- **IT assets** increased by $11.1 million or 10 percent primarily due to investment in hardware equipment within the IT/OT Systems program (Exhibit 2B, Section E8.4).

3.3 2022 Historical versus 2023 Bridge PP&E NBV

Table 8 below presents the 2022 actual versus 2023 bridge PP&E NBV values by asset class.

Table 8: 2022 Historical versus 2023 Bridge PP&E NBV ($ Millions)

	2022 Actual	2023 Bridge	Variance ($)	Variance (%)
Land and Buildings	205.3	222.1	16.8	8%
Other Distribution Assets	674.0	722.8	48.8	7%
General Plant	270.0	311.6	41.7	15%
TS Primary Above 50	37.9	75.7	37.8	100%
Distribution System	298.6	314.5	15.8	5%
Poles, Wires	4,185.9	4,605.8	419.8	10%
Contributions and Grants	(586.0)	(745.3)	(159.4)	27%
Line Transformers	867.2	942.2	75.0	9%
Services and Meters	418.4	439.9	21.4	5%

	2022 Actual	2023 Bridge	Variance ($)	Variance (%)
Equipment	204.8	239.7	34.9	17%
IT Assets	121.1	138.3	17.3	14%
Gross Assets	**6,697.2**	**7,267.3**	**570.1**	**9%**
Accumulated Depreciation	(1,803.4)	(2,023.0)	(219.6)	12%
Closing PP&E NBV	**4,893.9**	**5,244.3**	**350.5**	**7%**

From 2022 to 2023, PP&E by asset class variances are forecasted as follows:

- **Land and Buildings Assets** are forecasted to increase by $16.8 million or 8 percent primarily due to in-service amounts related to Copeland TS Phase 2 within the Stations Expansion program (Exhibit 2B, Section E7.4) and Facilities Management and Security (Exhibit 2B, Section E8.2)
- **Other Distribution Assets** are forecasted to increase by $48.8 million or 7 percent primarily due to IT software additions (Exhibit 2B, Section E8.4).
- **General Plant Assets** are forecasted to increase by $41.7 million or 15 percent primarily due to the in-service amounts related to Control Operations Reinforcement program (Exhibit 2B, Section E4.1.4) and the Facilities Management and Security program (Exhibit 2B, Section E8.2).
- **TS Primary Above 50** assets are forecasted to increase by $37.8 million or 100 percent due to the in-service amounts related to Copeland TS Phase 2 project in the Stations Expansion program (Exhibit 2B, Section E7.4).
- **Distribution System assets** are forecasted to increase by $15.8 million or 5 percent, primarily due to in-service additions related to Stations Renewal projects (Exhibit 2B, Section E6.6).
- **Poles and Wires Assets** are forecasted to increase by $419.8 million, or 10 percent, as a result of in-service additions from investments in the following programs: Customer Connections (Exhibit 2B, Section E5.1), Externally Initiated

Plant Relocations & Expansion (Exhibit 2B, Section E5.2), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and the Overhead System Renewal Program (Exhibit 2B, Section E6.5). Of these programs, the largest increases were from the Customer Connections ($137.4 million) and the Externally Initiated Plant Relocations & Expansion ($80.9 million) programs, followed by increases in planned renewal work as part the Underground System Renewal – Horseshoe program ($68.1 million) and other renewal work programs noted above.

- **Contributions and Grants** are forecasted to increase by $159.4 million or 27 percent due to customer and third-party contributions related to the Customer Connections and Externally Initiated Plant Relocations & Expansion programs. The contributions resulted in a reduction to NBV.
- **Line Transformers** are forecasted to increase by $75.0 million or 9 percent primarily due to Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and the Customer Connections (Exhibit 2B, Section E5.1) programs.
- **Services and Meter Assets** are forecasted to increase by $21.4 million or 5 percent primarily due to the Customer Connections (Exhibit 2B, Section E5.1) and the Metering (Exhibit 2B, Section E5.4) programs.
- **Equipment Assets** are forecasted to increase by $34.9 million or 17 percent, primarily due to investment in the Fleet and Equipment Services (Exhibit 2B, Section E8.3) and the Network Condition Monitoring & Control (Exhibit 2B, Section E7.3) programs.
- **IT assets** are forecasted to increase by $17.3 million or 14 percent primarily due to investment in hardware within the IT/OT program (Exhibit 2B, Section E8.4).

3.4 2023 Bridge versus 2024 Bridge PP&E NBV

Table 9 below presents the 2023 bridge versus 2024 bridge PP&E NBV values by asset class.

Table 9: 2023 Bridge versus 2024 Bridge PP&E NBV ($ Millions)

	2023 Bridge	2024 Bridge	Variance ($)	Variance (%)
Land and Buildings	222.1	229.9	7.8	3%
Other Distribution Assets	722.8	815.8	93.0	13%
General Plant	311.6	327.9	16.2	5%
TS Primary Above 50	75.7	82.1	6.4	8%
Distribution System	314.5	332.9	18.4	6%
Poles, Wires	4,605.8	5,017.8	412.1	9%
Contributions and Grants	(745.3)	(898.8)	(153.4)	21%
Line Transformers	942.2	1,027.2	85.0	9%
Services and Meters	439.9	476.5	36.6	8%
Equipment	239.7	262.1	22.4	9%
IT Assets	138.3	154.6	16.2	12%
Gross Assets	**7,267.3**	**7,827.9**	**560.6**	**8%**
Accumulated Depreciation	(2,023.0)	(2,249.2)	(226.2)	11%
Closing PP&E NBV	**5,244.3**	**5,578.8**	**334.4**	**6%**

From 2023 to 2024, PP&E by asset class variances are forecasted as follows:

- **Land and Buildings Assets** are forecasted to increase by $7.8 million or 3 percent primarily due to in-service amounts related to Facilities Management and Security (Exhibit 2B, Section E8.2).
- **Other Distribution Assets** are forecasted to increase by $93 million or 13 percent, primarily due to IT software additions (Exhibit 2B, Section E8.4), including the Customer Information System upgrade project ($64.7 million).

- **General Plant Assets** are forecasted to increase by $16.2 million or 5 percent primarily due to the in-service amounts related to the Facilities Management and Security program (Exhibit 2B, Section E8.2).
- **TS Primary Above 50** assets are forecasted to increase by $6.4 million or 8 percent due to the in-service amounts related to Copeland TS Phase 2 project in the Stations Expansion program (Exhibit 2B, Section E7.4).
- **Distribution System assets** are forecasted to increase by $18.4 million or 6 percent, primarily due to in-service additions related to Stations Renewal projects (Exhibit 2B, Section E6.6).
- **Poles and Wires Assets** are forecasted to increase $412.1 million or 9 percent as a result of in-service additions from investments in the following programs: Customer Connections (Exhibit 2B, Section E5.1), Externally Initiated Plant Relocations & Expansion (Exhibit 2B, Section E5.2), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and the Overhead System Renewal Program (Exhibit 2B, Section E6.5). Of these programs, the largest increases are forecasted in the Customer Connections ($125.6 million) and Externally Initiated Plant Relocations & Expansion ($78.5 million) programs, followed by increases in planned renewal work as part the Underground System Renewal – Horseshoe program ($69.9 million) and other renewal work programs noted above.
- **Contributions and Grants** are forecasted to increase by $153.4 million or 21 percent due to customer and third-party contributions related to the Customer Connections and Externally Initiated Plant Relocations & Expansion programs. The contributions resulted in a reduction to NBV.
- **Line Transformers** are forecasted to increase by $85.0 million or 9 percent primarily from in-service additions related to the Reactive and Corrective Capital

(Exhibit 2B, Section E6.7), Overhead System Renewal (Exhibit 2B, Section E5.1), Customer Connections (Exhibit 2B, Section E5.1) and Underground System Renewal- Horseshoe (Exhibit 2B, Section E6.2) programs.

- **Services and Meter Assets** are forecasted to increase by $36.6 million or 8 percent primarily due to the Metering program (Exhibit 2B, Section E5.4).
- **Equipment Assets** are forecasted to increase by $22.4 million or 9 percent, primarily due to investment in the Network Condition Monitoring & Control (Exhibit 2B, Section E7.3) and the Fleet and Equipment Services (Exhibit 2B, Section E8.3) programs.
- **IT assets** are forecasted to increase by $16.2 million or 12 percent, primarily due to investment in hardware within the IT/OT program (Exhibit 2B, Section E8.4).

3.5 2024 Bridge versus 2025 Forecast Year PP&E NBV

Table 10 below presents the 2024 bridge versus 2025 forecast PP&E NBV values by asset class.

Table 10: 2024 Bridge versus 2025 Forecast PP&E NBV ($ Millions)

	2024 Bridge	2025 Forecast	Variance ($)	Variance (%)
Land and Buildings	229.9	237.7	7.8	3.4%
Other Distribution Assets	815.8	877.7	61.9	7.6%
General Plant	327.9	338.7	10.8	3.3%
TS Primary Above 50	82.1	81.3	(0.8)	-0.9%
Distribution System	332.9	368.4	35.6	10.7%
Poles, Wires	5,017.8	5,423.6	405.8	8.1%
Contributions and Grants	(898.8)	(1,008.6)	(109.9)	12.2%
Line Transformers	1,027.2	1,110.7	83.5	8.1%
Services and Meters	476.5	526.6	50.1	10.5%
Equipment	262.1	286.7	24.6	9.4%

/C

	2024 Bridge	2025 Forecast	Variance ($)	Variance (%)
IT Assets	154.6	176.1	21.5	13.9%
Gross Assets	**7,827.9**	**8,418.8**	**590.9**	**7.5%**
Accumulated Depreciation	(2,249.2)	(2,484.3)	(235.2)	10.5%
Closing PP&E NBV	**5,578.8**	**5,934.5**	**355.7**	**6.4%**

/C

From 2024 to 2025, PP&E by asset class variances are forecasted as follows:

- **Land and Buildings Assets** are forecasted to increase by $7.8 million or 3.4 percent from in-service additions related to Facilities Management and Security (Exhibit 2B, Section E8.2) and Stations Renewal (Exhibit 2B, Section E6.6).
- **Other Distribution Assets** are forecasted to increase by $61.9 million or 7.6 percent primarily due to IT software additions (Exhibit 2B, Section E8.4), and capital contributions paid to Hydro One (Exhibit 2B, Section E7.4).
- **General Plant Assets** are forecasted to increase by $10.8 million or 3.3 percent primarily due to the in-service amounts related to the Facilities Management and Security program (Exhibit 2B, Section E8.2).
- **Distribution System assets** are forecasted to increase by $35.6 million or 10.7 percent, primarily due to in-service additions related to Stations Renewal projects (Exhibit 2B, Section E6.6).
- **Poles and Wires Assets** are forecasted to increase by $405.8 million or 8.1 percent /C
as a result of in-service additions from investments in the following programs: Customer Connections (Exhibit 2B, Section E5.1), Externally Initiated Plant Relocations & Expansion (Exhibit 2B, Section E5.2), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and the Overhead System Renewal Program (Exhibit 2B, Section E6.5). Of these programs, the largest increases are forecasted in the Customer Connections ($128.8 million) and Externally Initiated Plant Relocations &

Expansion ($73.4 million) programs, followed by increases planned renewal work as part the Underground System Renewal – Horseshoe program ($48.5 million) and other renewal work programs noted above.

- **Contributions and Grants** are forecasted to increase by $109.9 million or 12.2 percent due to customer and third-party contributions related to the Customer Connections and Externally Initiated Plant Relocations & Expansion programs. The contributions resulted in a reduction to NBV.
- **Line Transformers** are forecasted to increase by $83.5 million or 8.1 percent primarily from in-service additions related to Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and Customer Connections ($16.8 million, Exhibit 2B, Section E5.1) programs.
- **Services and Meter Assets** are forecasted to increase by $50.1 million or 10.5 percent primarily due to the Metering program (Exhibit 2B, Section E5.4).
- **Equipment Assets** are forecasted to increase by $24.6 million or 9.4 percent, /C primarily due to investment in the Network Condition Monitoring & Control (Exhibit 2B, Section E7.3) and the Fleet and Equipment Services (Exhibit 2B, Section E8.3) programs.
- **IT assets** are forecasted increase by $21.5 million or 13.9 percent primarily due to investment in computer hardware within the IT/OT program (Exhibit 2B, Section E8.4).

3.6 2025 versus 2029 Forecast Year PP&E NBV

Table 11 below presents the 2025 forecast versus 2029 forecast PP&E NBV values by asset class.

Table 11: 2025 Forecast versus 2029 Forecast ($ Millions)

	2025 Forecast	2029 Forecast	Variance ($)	Variance (%)
Land and Buildings	237.7	302.3	64.7	27.2%
Other Distribution Assets	877.7	1,210.3	332.6	37.9%
General Plant	338.7	459.1	120.4	35.5%
TS Primary Above 50	81.3	78.3	(3.0)	-3.7%
Distribution System	368.4	523.9	155.5	42.2%
Poles, Wires	5,423.6	7,488.3	2,064.6	38.1%
Contributions and Grants	(1,008.6)	(1,617.8)	(609.1)	60.4%
Line Transformers	1,110.7	1,461.2	350.5	31.6%
Services and Meters	526.6	733.9	207.3	39.4%
Equipment	286.7	370.6	83.8	29.2%
IT Assets	176.1	295.1	119.0	67.6%
Gross Assets	**8,418.8**	**11,305.1**	**2,886.3**	**34.3%**
Accumulated Depreciation	(2,484.3)	(3,583.2)	(1,098.8)	44.2%
Closing PP&E NBV	**5,934.5**	**7,722.0**	**1,787.5**	**30.1%**

/C

From 2025 to 2029, PP&E by asset class variances are forecasted as follows:

- **Land and Buildings Assets** are forecasted to increase by $64.7 million or 27.2 percent, primarily from in-service additions related to Facilities Management and Security ($33 million) per Exhibit 2B, Section E8.2, the Stations Renewal work ($16.7 million) per Exhibit 2B, Section E6., and 6 the Downsview TS project ($15 million) per Exhibit 2B, Section E7.4.
- **Other Distribution Assets** are forecasted to increase by $332.6 million or 37.9 /C percent primarily due to the in-service amounts related to IT software additions ($155.3 million) per Exhibit 2B, Section E8.4, capital contributions paid to Hydro /C One ($84.4 million) per Exhibit 2B, Section E7.4, and Stations Renewal ($37.2 /C million) per Exhibit 2B, Section E6.6.

- **General Plant Assets** are forecasted to increase $120.4 million or 35.5 percent primarily due to the in-service amounts for Facilities Management and Security program ($80.4 million) per Exhibit 2B, Section E8.2, and the Enterprise Data Centre project ($37.5 million) per Exhibit 2B, Section E8.1.
- **TS Primary Above 50** are forecasted to decrease by $3 million or 3.7 percent due to depreciation expenses being higher than in-service additions.
- **Distribution System Assets** are forecasted to increase by $155.5 million or 42.2 /C percent primarily due to Stations Renewal projects ($95.8 million) per Exhibit 2B, Section E6.6 and work in the Metering program ($49.8 million) per Exhibit 2B, Section E5.4.
- **Poles and Wires Assets** are forecasted to increase by $2,064.6 million or 38.1 /C percent primarily due to:
  - Demand-related investments in the Customer Connections program ($593.2 million) per Exhibit 2B, Section E5.1, and the Externally Initiated Plant Relocations and Expansion program ($281.6 million) per Exhibit 2B, Section E5.2;
  - Planned renewal work in the Underground System Renewal – Horseshoe ($305.2 million) per Exhibit 2B, Section E6.2 and Overhead System Renewal ($147.3 million) per Exhibit 2B, Section E6.5.
- **Contributions and Grants** are forecasted to increase by $609.1 million or 60.4 percent due to customer and third-party contributions related to the Customer Connections and Externally Initiated Plant Relocations & Expansion programs. The contributions resulted in a reduction to NBV.
- **Line Transformers** are forecasted to increase by $350.5 million or 31.6 percent /C primarily from in-service additions related to Reactive and Corrective Capital program ($88.8 million) per Exhibit 2B, Section E6.7, the Customer Connections

program ($77.2 million) per Exhibit 2B, Section E5.1, the Overhead System Renewal program ($61.8 million) per Exhibit 2B, Section E6.5, and the Network System Renewal program ($49.7 million) per Exhibit 2B, Section E6.4.

- **Services and Meter Assets** are forecasted to increase by $207.3 million or 39.4 percent primarily due to the implementation of the Advanced Metering Infrastructure (AMI2.0) project per Exhibit 2B, Section E5.4.
- **Equipment Assets** are forecasted to increase by $83.8 million or 29.2 percent, primarily due to investment in the Network Condition Monitoring & Control (Exhibit 2B, Section E7.3) and the Fleet and Equipment Services (Exhibit 2B, Section E8.3) programs. /C
- **IT Assets** are forecasted to increase by $119.0 million or 67.6 percent primarily due to investment in hardware equipment ($85.3 million) per the IT/OT program in Exhibit 2B, Section E8.4, and the Enterprise Data Centre project ($32.7 million) per Exhibit 2B, Section E8.1.

DEPRECIATION AND AMORTIZATION

This schedule provides information about Toronto Hydro's depreciation and amortization rates and expenses. Toronto Hydro converted to International Financial Reporting Standards ("IFRS") effective January 1, 2015. This application represents Toronto Hydro's third rebasing application under Modified IFRS ("MIFRS").

1. FILING REQUIREMENTS

In accordance with s. 2.2.4 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022), this schedule provides the following information:

- Details regarding depreciation, amortization and depletion by asset group for the current (2020-2024) and future (2025-2029) rate periods;
- A description of Toronto Hydro's depreciation and amortization practices and a summary of the changes implemented since the utility's last rebasing application;
- An explanation of Toronto Hydro's variance from the "half-year rule" regarding the calculation of depreciation expense;
- An explanation to reconcile methodological differences between Toronto Hydro's depreciation expense and OEB Appendix 2-C; and
- Information about the utility's decommissioning provision and any associated depreciation or accretion expenses in relation to the decommissioning provision.

2. DEPRECIATION EXPENSE DETAILS

Appendix A to this schedule provides a summary of depreciation expense by Uniform System of Accounts for the current (2020-2024) and future (2025-2029) rate periods. These amounts include derecognition as described in Exhibit 2A, Tab 2, Schedule 2.

3. DEPRECIATION AND AMORTIZATION

In accordance with the OEB's Accounting Procedures Handbook for Electricity Distributors (the "APH"), Toronto Hydro depreciates and amortizes its assets on a straight-line basis over the estimated useful lives of the assets. Tables 1 and 2 below provide Toronto Hydro's annual depreciation and amortization rates by asset category for the current (2020-2024) and future (2025-2029) rate periods.

Table 1: Property, Plant, and Equipment Depreciation Rates (%)[1]

Asset Category	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge	2025-29 Forecast
Distribution Lines	1.7 - 5.0	1.7 - 5.0	1.7 - 5.0	1.5 - 5	1.5 - 5	1.5 - 5
Transformers	3.3 - 5.0	3.3 - 5.0	3.3 - 5.0	2.9 - 3.3	2.9 - 3.3	2.9 - 3.3
Meters	2.5 - 6.7	2.5 - 6.7	2.5 - 6.7	2.5 - 6.7	2.5 - 6.7	2.5 - 6.7
Stations	2.5 - 10.0	2.5 - 10.0	2.0 - 10.0	2.0 - 10.0	2.0 - 10.0	2.0 - 10.0
Buildings	1.3 - 5.0	1.3 - 5.0	1.3 - 5.0	1.5 - 10.0	1.5 - 10.0	1.5 - 10.0
Other Capital Assets	4.0 - 25.0	4.0 - 25.0	4.0 - 25.0	4.0 - 25.0	4.0 - 25.0	4.0 - 25.0
Right-of-use assets	1.0 - 11.1	1.0 - 11.1	1.0 - 11.1	1.0 - 11.1	1.0 - 11.1	1.0 - 11.1

Table 2: Intangible Assets Amortization Rates (%)

Asset Category	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge	2025-29 Forecast
Computer Software	10.0 - 25.0	10.0 - 25.0	10.0 - 25.0	10.0 - 25.0	10.0 - 25.0	10.0 - 25.0
Contributions	4.0	4.0	4.0	4.0	4.0	4.0

[1] Toronto Hydro added new asset classes and made minor presentation changes to the grouping of asset categories related to depreciation. Specifically: (1) the Streetlighting and Signal Systems and Storage Battery Equipment assets were rolled into the Other Capital asset category; and (2) assets under the Building category were re-categorized to better align with actual use.

3.1 Depreciation Study

In accordance with the OEB's decision in the 2020-2024 Rate Application (EB-2018-0165), Toronto Hydro retained Concentric Advisors, ULC ("Concentric") to complete a Depreciation study, which is filed as Appendix D to this schedule (the "Study"). The Study resulted in changes to depreciation rates effective January 1, 2023.

As summarized in Appendix D at Tables 1 – 3, the financial average service lives of six asset classes were shortened by the Study, and the financial average service lives of 73 asset were lengthened by Study, resulting in a significant overall reduction in depreciation expenses. Concentric concludes at section 1, page 1 of the report in Appendix D, that the lengthening of average service lives is consistent with trends observed throughout the North American electric industry, due to many factors including the increased focus of utilities in maintaining and extending the life of infrastructure.

At Toronto Hydro's request, in the 2023 Decision and Rate Order (EB-2022-0065) issued on December 8, 2022, the OEB approved a new variance account ("Useful Life Changes") "*to separately track the difference in revenue requirement impacts between the existing and updated depreciation rates over the 2023 and 2024 period, in a new sub-account of its existing capital-related revenue requirement variance account (CRRRVA)*." The total revenue requirement impact of the change in depreciation rates using Toronto Hydro's proposed approach is $136.5 million as of the end of 2024. For further details about the calculation of the balance, including a comparison of Toronto Hydro's proposed approach and the methodology proposed by OEB Staff, please refer to Exhibit 9, Tab 1, Schedule 1.

Appendix 2-BB contains the updated useful lives. Assets that fall outside the Kinectrics Report useful life ranges are supported by the Study.

3.2 Variance from Half-Year Rule

Toronto Hydro calculates depreciation based on the month that an asset comes into service, rather than on the basis of the half-year rule, which assumes that all asset additions are put into service in the middle of the fiscal year. Similarly, Toronto Hydro calculates depreciation associated with assets that are retired, transferred or become fully depreciated within a given year based on the month of transaction. This practice is consistent with past rate applications reviewed by the OEB.

4. DECOMMISSIONING PROVISION

Toronto Hydro recognizes liabilities for the future removal and handling costs for contamination in distribution equipment and for the future environmental remediation of certain properties (collectively known as "decommissioning provisions") in accordance with Article 410 of the OEB Accounting Procedures Handbook for Electricity Distributors (the "APH").

A decommissioning provision is recognized at the time that the obligation arises. Initially, Toronto Hydro measures the liability at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the utility depreciates the capitalized amount over the useful life of the related asset and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability ("accretion expense") and for changes in the underlying assumptions.

Tables 3 and 4 below sets out Toronto Hydro's decommissioning costs and the related depreciation expense for the current (2020-2024) and future (2025-2029) rate periods. Tables 5 and 6 below shows the corresponding decommissioning liability and related accretion expense over the same periods. The methodology to forecast decommissioning provisions is consistent with the last rebasing application.[2]

Table 3: Actual and Bridge Decommissioning Costs & Related Depreciation Expense ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Decommissioning Costs	0.7	0.5	0.2	0.2	0.1
Related Depreciation Expense	0.1	0.1	0.0	0.0	0.0

Table 4: Forecast Decommissioning Costs & Related Depreciation Expense ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Decommissioning Costs	0.1	0.0	(0.0)	(0.0)	(0.1)
Related Depreciation Expense	0.0	0.1	0.0	0.0	0.0

Table 5: Actual and Bridge Decommissioning Liability & Related Accretion Expense ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Decommissioning Liability	1.4	1.1	0.8	0.6	0.5
Related Accretion Expense	-	-	-	-	-

Table 6: Forecast Decommissioning Liability & Related Accretion Expense ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Decommissioning Liability	0.5	0.5	0.5	0.5	0.4
Related Accretion Expense	-	-	-	-	-

[2] EB-2018-0165 at Exhibit 4B, Tab 1, Schedule 1.

5. DEPRECIATION AND AMORTIZATION EXPENSE

Tables 7 and 8 below summarize the depreciation and amortization expense reflected in the Revenue Requirement presented in Exhibit 6, Tab 1, Schedule 1 and in OEB Appendix 2-BA at Exhibit 2A, Tab 1, Schedule 2.

Table 7: Depreciation and Amortization Expense[3] 2020 to 2024 ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Depreciation and Amortization Expense[4]	237.8	250.7	262.0	229.0	237.2

Table 8: Depreciation and Amortization Expense[5] 2025 to 2029 ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	
Depreciation and Amortization Expense[6]	247.4	260.1	278.5	300.1	311.2	/C

Depreciation and amortization expense results from detailed calculations by asset class which are determined through the utility's enterprise financial system for historical amounts, and financial models for the bridge and forecast years. This method incorporates the depreciation and amortization rates presented in Tables 1 and 2 above, and considers the actual and forecasted timing of asset additions and removals from service.

The year-over-year increases in depreciation and amortization expense summarized above are primarily due to Toronto Hydro's in-service asset additions summarized in Exhibit 2A,

[3] Includes depreciation of the decommissioning costs and excludes derecognition. See Exhibit 2A, Tab 2, Schedule 2 for information about asset derecognition.
[4] See Exhibit 2A, Tab 2, Schedule 1, Appendix A for additional information.
[5] Includes depreciation of the decommissioning costs and excludes derecognition. See Exhibit 2A, Tab 2, Schedule 2 for information about asset derecognition.
[6] See Exhibit 2A, Tab 2, Schedule 1, Appendix A for additional information.

Tab 1, Schedule 1, with the exception of 2022 versus 2023 where there is a decrease as a result of implementing the revised rates resulting from the Study.

5.1 OEB Appendix 2-C

OEB's Appendix 2-C is filed as Appendix B to this schedule. The utility notes that the depreciation and amortization values in Appendix 2-C are based on broad assumptions. As a result, differences in depreciation and amortization values calculated by the financial system and using the formulas in Appendix 2-C are expected. For example, Appendix 2-C assumes depreciation in the first year, for all assets placed into service, begins at mid-year while Toronto Hydro depreciates assets from the month they are capitalized. In addition, applying broad depreciation assumptions to assets within an account that contains assets with varying remaining useful lives depending on when they were put in-service, also creates differences in depreciation and amortization in Appendix 2-C.

DERECOGNITION OF ASSETS

Article 410 of the OEB Accounting Procedures Handbook for Electricity Distributors requires property, plant and equipment ("PP&E") and intangible assets to be derecognized upon disposal, or when their use is no longer expected to offer future economic benefits. The gain or loss arising from the derecognition of PP&E and intangible assets is calculated as the difference between the net disposal proceeds (if any) and the carrying amount of the item, and is included in the utility's profit or loss during the period in which the item is derecognized.

Table 1 below summarizes 2020-2022 actual and 2023-2024 forecasted derecognition. Table 2 summarizes the forecasted derecognition for the 2025-2029 period. The forecast is informed by the utility's capital expenditure proposals outlined in the Distribution System Plan (Exhibit 2B, Section E4), and calculated on the basis of the net book values associated with assets that the utility expects to remove from service as part of its planned capital program. The methodology to forecast derecognition is consistent with the last rebasing application.[1]

Table 1: 2020-2024 Derecognition ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Derecognition	23.2	24.0	25.0	28.0	33.5

Table 2: 2025-2029 Derecognition ($ Millions)

	2025	2026	2027	2028	2029	
Derecognition	37.5	38.7	40.8	41.9	42.6	/C

[1] EB-2018-0165 at Exhibit 4B, Tab 1, Schedule 2; and 9-Staff-156 at page 3.

COST OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING GENERATION FACILITIES

This schedule summarizes the treatment of costs incurred to connect, or enable the connection, of Renewable Energy Generation ("REG") facilities to Toronto Hydro's distribution system, as eligible investments for provincial rate recovery under section 79.1 of the *Ontario Energy Board Act, 1998*.[1] Chapter 5.3 and Appendix A of the OEB's Filing Requirements for Electricity Distributor Rate Applications invites distributors to apply for provincial rate protection associated with costs incurred to make eligible investments.[2]

1. REG CONNECTIONS

As of December 31, 2022, Toronto Hydro connected 2,280 REG projects representing over 116.2 MW of capacity, and completed approximately 751 MW of pre-assessment capacity reviews. Toronto Hydro anticipates over 1,700 new REG connections during the 2023 through 2029 period, with a corresponding capacity of 74 MW. By the end of the decade, the utility forecasts approximately 200 MW of total REG capacity connected to its grid.[3]

As part of its capacity planning process outlined in Exhibit 2B, Section D4, the utility identified a number of constraints that impact DER (including REG) connections to the distribution grid, including: limited breaker and station equipment capacity due to short circuit capacity constraints; reverse power flow limitations based on transformer thermal capacity and minimum load requirements; anti-islanding conditions for DG; and system thermal limits and load transfer capability.

[1] Cost Recovery re Section 79.1 of the Act, O. Reg. 330/09, at s. 1(2).
[2] See also O. Reg. 330/09 made under the Act.
[3] For further information, please refer to Customer Connections (Exhibit 2B, Section E5.1).

Short circuit capacity constraints on station equipment are the primary constraint for REG connections. To determine the short circuit capacity at stations and other locations on the distribution system, Toronto Hydro employs sophisticated fault and power flow simulation models. These models predict how much fault current will flow to a specific location from generators located throughout the distribution system. The presence of REG on distribution feeders can contribute to fault current that can cause station equipment, such as circuit breakers, to exceed short circuit capacity limits. Toronto Hydro completes a study for each new REG application to monitor the available existing short circuit capacity of the system.

2. REI INVESTMENT SUMMARY

To address the above-noted constraints at the distribution level, Toronto Hydro intends to undertake a number of Renewable Enabling Improvement ("REI") investments as part of its 2025-2029 Distribution System Plan ("DSP") filed at Exhibit 2B.

2.1 Generation Protection, Monitoring, and Control (GPMC) Program

The GPMC program includes two types of REI investments:

- **Bus-Tie Reactors**: Bus-tie reactors lower the short circuit current on the station bus and distribution system by insertion of an impedance at the bus-tie point. Toronto Hydro proposes to work with Hydro One to install bus-tie reactors at Richview, Runnymede, Cecil, Esplanade, Leslie and Woodbridge TS to eliminate the existing fault current constraint, which will enable REG connections. For additional details, please refer to the Generation Protection, Monitoring, and Control (GPMC) Program (Exhibit 2B, Section E5.5).
- **Remote Monitoring and Control of Generation (SCADA)**: During the 2020-2024 plan period, Toronto Hydro is installing monitoring and control systems for all new distributed generation ("DG") connections. These real-time monitoring and control

systems communicate with REG resources via communication networks connected to the utility's supervisory control and data acquisition ("SCADA") system to enable safe operation of the distribution system and feeder management of bi-directional distribution grid flows. The technology provides system planners and operators real-time visibility to manage generation-to-load ratios within tolerable levels and ensure that the anti-islanding feature of DG facilities operate in the event of a distribution system fault.

Toronto Hydro must continue to invests in the GPMC program to enable safe and reliable connection and integration of REG resources in the 2025-2029 rate period. In accordance with the DSC, the utility's costs associated with installing monitoring and control technology are limited to REG resources, as non-renewable generation projects bear the cost of this technology.

2.2 Energy Storage

Studies show that significant penetration of REG can lead to destabilizing grid parameters.[4] Energy storage systems ("ESS") can be leveraged to stabilize the grid by balancing the minimum load to generation ratios ("MLGR") on feeders with REG connections. Rather than curtailing the generation output of REG facilities connected to feeders where minimum load is low, renewable enabling ESS can be deployed (as a load) to increase the load to generation ratio to the recommended threshold. Toronto Hydro plans to deploy nine energy storage systems with an aggregate capacity of 10.2 MW on nine distribution feeders that are forecast to have high generator to minimum load ratios over the 2025-2029 period.

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[4] M. Begovic et. al., *Impact of Renewable Distributed Generation on Power Systems*, Proceedings of the 34th Hawaii International Conference on System Sciences (2001), available at <https://pserc.wisc.edu/ecow/get/publicatio/2000public/CSSAR01.PDF>.

In the 2020-2024 Decision (EB-2018-0165), the OEB directed Toronto Hydro to provide an assessment of the appropriate share of benefits for ESS projects as a part of future requests for funding for provincial rate application when ESS projects may provide additional benefits to the distribution system, like demand response and grid capacity relief.[5] However, Toronto Hydro notes that the 2020-2024 ESS program included proposed investments in grid performance ESS and customer-specific ESS, in addition to renewable enabling ESS.[6] In the 2025-2029 rate period, Toronto Hydro's ESS program targets the enablement of REG connections and does not contemplate additional use cases to support the distribution system. As a result, Toronto Hydro proposes to apply the generic 6 percent direct benefit assumption for enabling improvement investments in accordance with the Chapter 2 Filing Requirements.[7]

2.3 Stations Expansion

Over the 2025-2029 period, Toronto Hydro needs to expand Sheppard TS to alleviate system constraints for connecting DERs in this area. The currently available short circuit capacity of the Sheppard TS EZ bus in 2023 is -57.3 MVA, indicating a significant lack of short circuit capacity which will persist into the future. By 2029, the constraints are expected to worsen to -91.4MVA. The new bus at Sheppard TS will introduce an estimated 126 MVA of new short circuit capacity at the station to enable DER growth. The utility selected this option due to the technical limitations of installing a bus-tie reactor to the Gas Insulated Switchgear (GIS) bus at Sheppard TS.[8] /C

[5] EB-2018-0165, Decision and Order (December 19, 2019) at pages 117 and 119.
[6] Ibid. at pages 109-110.
[7] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 2 (December 15, 2022), Appendix A.
[8] For more details regarding the limitations, please refer to Exhibit 2B, Section E5.5 – Generation, Protection, Monitoring and Control and Exhibit 2B, Section E7.4 – Stations Expansion. /C

2.4 IESO Letter of Comment Regarding REG Investments

The IESO reviewed Toronto Hydro's REG investment plans, and confirmed that the forecasted REG and other DER connections are an input to the regional planning process. For more information, please refer to Exhibit 2B, Section B at Appendix G.

3. ELIGIBLE INVESTMENTS COSTS

Table 1 summarizes the cost of planned REI investments in 2025 to 2029 rate period.[9]

Table 1: Renewable Enabling Improvements ("REI") from 2025-2029 ($ Millions)

Capital Program	2025	2026	2027	2028	2029	Total	
Generation, Protection, Monitoring, and Control	5.9	6.1	6.3	6.5	10.3	35.0	
Energy Storage	3.6	3.6	7.5	3.8	4.0	22.5	
Stations Expansion – Sheppard TS Bus Expansion	-	0.5	4.5	5.0	5.0	15.0	/C
Totals	**9.5**	**10.2**	**18.3**	**15.3**	**19.3**	**72.5**	/C

4. PROVINCIAL RATE PROTECTION

Toronto Hydro applied the six percent direct benefit percentage provided by the OEB with respect to REI investments to calculate the provincial rate protection amounts. The detailed breakdown is provided in the OEB Appendices 2-FA and 2-FB at Exhibit 2A, Tab 5, Schedules 2 to 6.[10] Three versions of the OEB Appendices 2-FA and 2-FB are filed: one for Energy Storage, one for Generation, Protection, Monitoring, and Control systems, and one for Stations Expansion. This is necessary, as the useful lives of these assets are different. /C Further, the OEB Appendices reflect the 2020 opening balances, which arise from the REI in

[9] Toronto Hydro is not proposing any specific Renewable Expansion investments during 2025-2029.
[10] Appendix 2-FC provided in Schedule 4 is not applicable.

the utility's 2020-2024 Rate Application.[11] The opening balances reflect the current forecast for REI programs previously approved by the OEB.

[11] EB-2018-0165, Decision and Order (December 19, 2019).

D4 Capacity Planning, Growth & Electrification

Toronto Hydro's capacity plan ensures that the distribution system is adequately sized to deliver reliable electricity to the utility's customers. To that end, the capacity planning process considers new load connections, increased distributed energy resources ("DERs") and broader electrification activities including the electrification of transportation. Fundamental to the capacity planning process is a 10-year weather-adjusted peak demand forecast ("System Peak Demand Forecast") that is developed using a driver-based forecasting methodology. The System Peak Demand Forecast is the basis for the Regional Planning forecast at the needs assessment stage to assess the adequacy of transmission facilities to supply the distribution grid.[1]

Capacity planning is becoming more complex as utilities address the unprecedented energy transition that is set to unfold over the coming years. National, provincial, and municipal decarbonization targets, as well as technical, societal, and economic factors are driving toward a decarbonized, decentralized and digitized energy system. This shift is expected to expand the role of clean electricity as source of energy for transportation and heating. Despite explicit industry and government net zero emission targets, there are still degrees of uncertainty around how these ambitious goals will be achieved. The pace and timing of the resulting growth and electrification from the pursuit of these targets will be driven by a complex interplay of policy, technological developments and consumer choice. Distribution system capacity planning must manage these interlinked growth drivers in an environment of greater uncertainty. Section D4.3 provides an overview of how Toronto Hydro has addressed this complexity and managed this uncertainty in its investment planning for 2025-2029.

For the 2025-2029 rate period, Toronto Hydro undertook enhanced capacity and connections capability assessments to monitor capacity related risks within its system. The enhancements include the preparation of the System Peak Demand Forecast with additional inputs for electric vehicles ("EVs"), data centers and Municipal Energy Plans, assessment of spare feeder positions, identification of system constraints that impact generation connections, and identification of unique drivers for demand growth.

Toronto Hydro also augmented its decision-making process with the results of long-term scenario modelling tool known as Future Energy Scenarios. The Future Energy Scenarios model is distinct from

[1] Please refer to Exhibit 2B, Section B for more information about Toronto Hydro's role in the Regional Planning Process.

the System Peak Demand Forecast in that it does not attempt to determine the most likely demand based on historical trends and other probabilistic sources of information. Rather, the Future Energy Scenarios model projects what the demand would be under various policy, technology and consumer behaviour assumptions that are linked to the varying aspirations, goals, targets and constraints of decarbonizing the economy by 2040 or 2050. The Future Energy Scenarios is described in more detail in Appendix A to this schedule.

This Exhibit describes Toronto Hydro's approach to capacity planning for 2025-2029 and is organized into the following sub-sections:

- **Section D4.1** outlines the capacity planning approach,
- **Section D4.2** describes in impact of growth and electrification considerations on the capacity planning process, and
- **Section D4.3** describes capacity needs and investments over the 2025-2029 period.

D4.1 Capacity Planning

Through its capacity planning process, Toronto Hydro assesses the adequacy of the distribution grid to deliver safe and reliable electricity to current and future customers. This process is linked with Regional Planning to ensure the adequacy of transmission facilities supplying the distribution grid. The System Peak Demand Forecast is the basis for the capacity planning process both at the distribution level and for Regional Planning at the needs assessment stage.

D4.1.1 System Peak Demand Forecast

The System Peak Demand Forecast determines the grid capacity investments that Toronto Hydro needs to make in the 2025-2029 rate period in order to continue to serve its customers and support economic growth and development in the City of Toronto. Using a probabilistic approach to forecast the peak demand at all transformer station buses that supply Toronto Hydro's distribution grid, the System Peak Demand Forecast yields summer and winter demand peaks, with the summer peak driving the 2025-2029 investment plan.

To arrive at the System Peak Demand Forecast, Toronto Hydro modelled organic system growth as part of the base forecast along with specific drivers that are relevant and material to the planning horizon. More specifically, Toronto Hydro considered three new specific drivers in the development of the System Peak Demand Forecast: (i) hyperscale data centers, (ii) electrification of transportation and (iii) Municipal Energy Plans which include large anticipated connections in different areas of the city. Each of these drivers is discussed in further detail below.

The System Peak Demand Forecast methodology includes the following components and considerations:

1. Weather Normalization
2. Econometric Multivariate Regression
3. Hyperscale Data Centre Demand Driver Analysis
4. Electric Vehicle (EV) Demand Driver Analysis
5. Municipal Energy Plans – Uncommitted Connections
6. Monte-Carlo Simulation
7. TS Bus Growth Allocation & Layering of Load Transfers/Voltage Conversions and Customer Connections

D4.1.1.1 Weather Normalization

To determine the correlation between temperature and load, Toronto Hydro's analysis removed the impact of day-to-day fluctuations in temperature on peak load in order to arrive at a stable view of historical system performance. Toronto Hydro then applied the historical trend to the forecasted peak load to normalize the forecast for weather-related impacts.

D4.1.1.2 Econometric Multivariate Regression

In addition to weather, Toronto Hydro considered a range of macroeconomic assumptions as inputs to the System Peak Demand Forecast, including the following key variables:

1. Toronto Population
2. Toronto Employment Rate & Median Income
3. Consumer Price Index
4. Number of Business Licenses Issued/Renewed
5. Toronto Housing Starts
6. Average Home Price

Toronto Hydro relied on traditional forecasting approaches to establish a correlation between weather and peak demand, and between econometric variables and peak demand. Toronto Hydro enhanced the traditional approach by incorporating considerations of the impact of varying weather on economic activity and its relationship to peak demand. This analysis enabled the utility to assess the impact of a changing climate on the econometric variables that affect peak demand.

D4.1.1.3 Hyperscale Data Centre Demand Driver Analysis

Toronto Hydro identified hyperscale data center connections as a new driver of significant peak demand growth over the 2025-2029 rate period and beyond. A hyperscale data center supports large processing and data storage operations using 5,000 servers or more and has the capability of a peak demand exceeding 25 MW. In order to better understand the impact of hyperscale data center connections on the grid and plan accordingly, Toronto Hydro modelled this driver separately. Through review of historical load connections, research into growth rates for comparable North American cities, and assessments of vacancy rates as well as available land space in the City, Toronto Hydro assessed the peak demand contributions of hyperscale data centers.

D4.1.1.4 Electric Vehicle Demand Driver Analysis

Toronto Hydro forecasted the impact of light-duty, medium-duty and heavy-duty EVs. Figure 1 below summarizes the volumes of EVs that underpin the forecast. The adoption models are aligned with the City of Toronto’s Transform TO transportation electrification goals. The forecast also considered geographic distribution and typical charging profiles to arrive at area and system peak demand contribution from electric vehicle uptake by consumers.

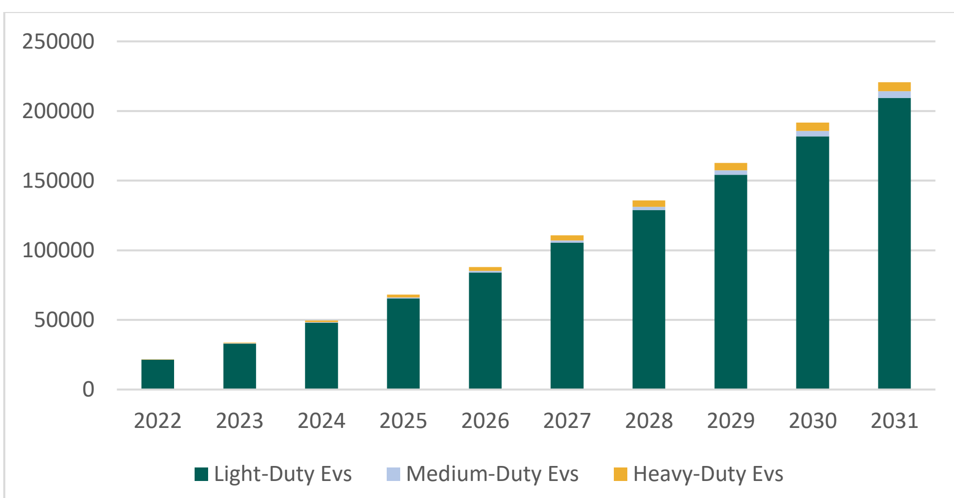

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Figure 1: Peak Demand Forecast – EV Volumes

D4.1.1.5 Municipal Energy Plans

In the development of the System Peak Demand Forecast, Toronto Hydro considered the impact of Municipal Energy Plans for large projects, such as the re-development of Downsview, Port Lands and Scarborough Golden Mile.[2] Figure 2, shows the location of these projects in the city.

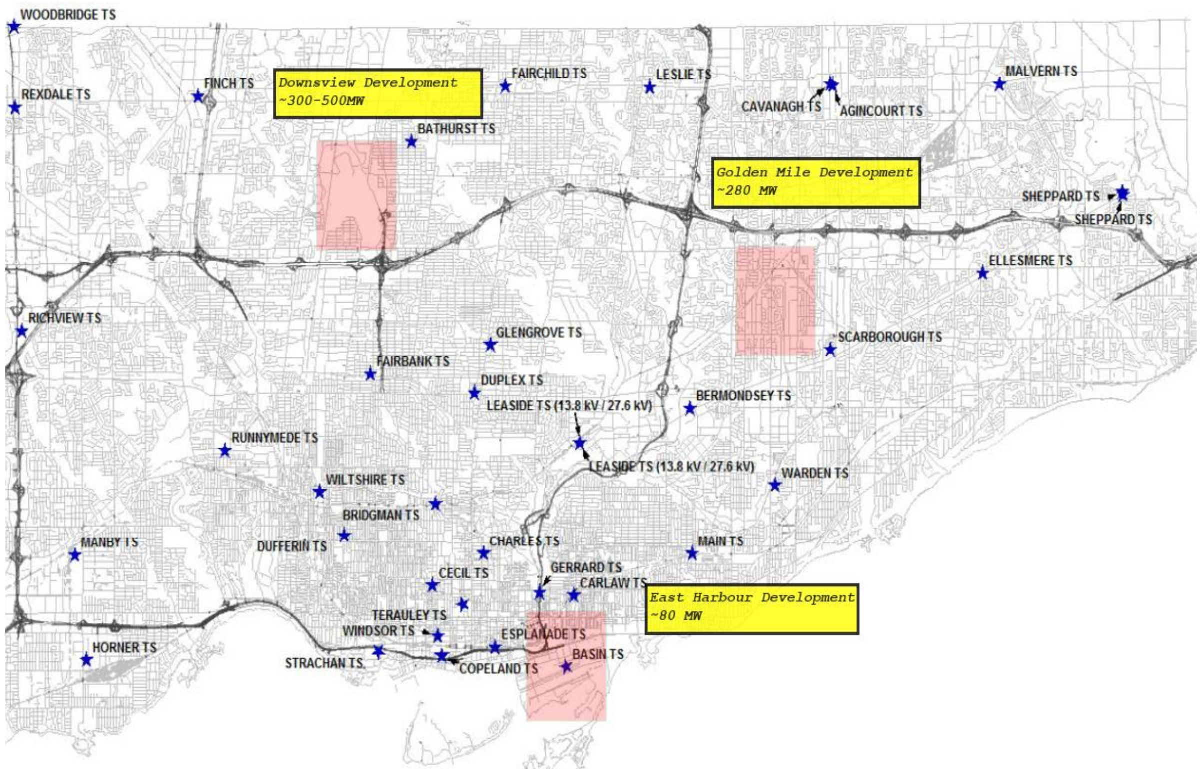

Figure 2: Municipal Energy Plan Locations

For the identified Municipal Energy Plans, Toronto Hydro included both firm connection commitments and the anticipated future loads in the System Peak Demand Forecast to ensure that the utility has sufficient lead-time to invest in new grid capacity that is required to serve this future demand. This approach is consistent with section 3.3.1 of the Distribution System Code which requires distributors to "plan and build the distribution system for reasonable forecast load growth." It is also aligned with the recommendation of the OEB's Regional Planning Process Advisory Group for distributors to incorporate Municipal Energy Plan information into their planning and forecasting

[2] City of Toronto, Official Plans – Secondary Plans, "online", https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/official-plan/chapter-6-secondary-plans/

processes in order to "identify current and future needs for new electricity infrastructure investments within local communities."[3]

D4.1.1.6 Monte-Carlo Simulation

Monte-Carlo Simulation is a sophisticated modelling technique that is applied to model the probability of different outcomes when the potential for random variables is present. It considers multiple sources of uncertainty to provide a range of possible outcomes for peak demand. For the System Peak Demand Forecast, Toronto Hydro modeled the variability of temperature to consider the impact of climate change on econometric indicators and simultaneously included drivers for data centers, electric vehicles, conservation and demand management, and distributed energy resources forecasts and applied a probability to determine the most likely outcome.

D4.1.1.7 TS Bus Growth Allocation and Layering of Load Transfers/Voltage Conversions and Customer Connections

The final step in the forecasting process involves allocating the demand outputs from each driver to the station buses and layering on any permanent load transfers through the Load Demand program to arrive at the System Peak Demand Forecast that describes impacts at both a system and bus level.

D4.1.2 Regional Planning Forecasts /C

The Toronto regional planning process commenced in the fall of 2022 with the needs assessment phase.[4] The transmitter Hydro One Networks Inc. develops the regional planning needs assessment forecast using an extreme weather model, information from Toronto Hydro's System Peak Demand Forecast and a forecast of Conservation and Demand Management (CDM) and Distributed Generation (DG) from the IESO. On March 21, 2023, the IESO issued the Scoping Assessment Outcome Report identifying the need for an Integrated Regional Resource Plan ("IRRP") for the Toronto Region. This process is currently underway.

/C

The Needs Assessment Report issued in December 2022, prepared on the basis of 2021 actuals, indicated that the net summer peak demand in the Toronto region is expected to increase by an average of 2.1 per cent per year, reaching 6,700 MVA by 2031.[5] In the fall 2023, as part of the IRRP

[3] RPPAG, Municipal Information Document – Improving the Electricity Planning Process in Ontario: Enhanced Coordination between Municipalities and Entities in the Electricity Sector, (December 15, 2022) p. 2, "online", https://www.oeb.ca/sites/default/files/RPPAG-Municipal-Information-Document-20221202.pdf
[4] Exhibit 2B, Section B
[5] Exhibit 2B, Section B, Appendix A – Needs Assessment Report (Toronto Region)

process, Toronto Hydro prepared the 2023 System Peak Demand Forecasts, on the basis of 2022 actuals and other modelling refinements, indicating that the net summer peak demand is expected to increase by an average of 2.6 percent per year, reaching 6,000 MVA by 2031.

Figure 3 below shows: (i) Toronto Hydro's 2022 System Peak Demand Forecast, which is consistent with the Regional Planning Forecast issued by Hydro One as part of the Needs Assessment; and (ii) Toronto Hydro's 2023 System Peak Forecast which was provided to the IESO in the fall of 2023 as an input to the Toronto Region IRRP process currently underway. The System Peak Demand Forecasts are shown net of the forecasted impacts of CDM and DG. The primary difference between the 2022 System Peak Demand Forecast and 2022 Regional Planning Needs Assessment forecasts is the effect of extreme weather. As noted above, Toronto Hydro normalizes its forecast for weather fluctuations, whereas the Regional Planning forecasts rely on an extreme weather model.

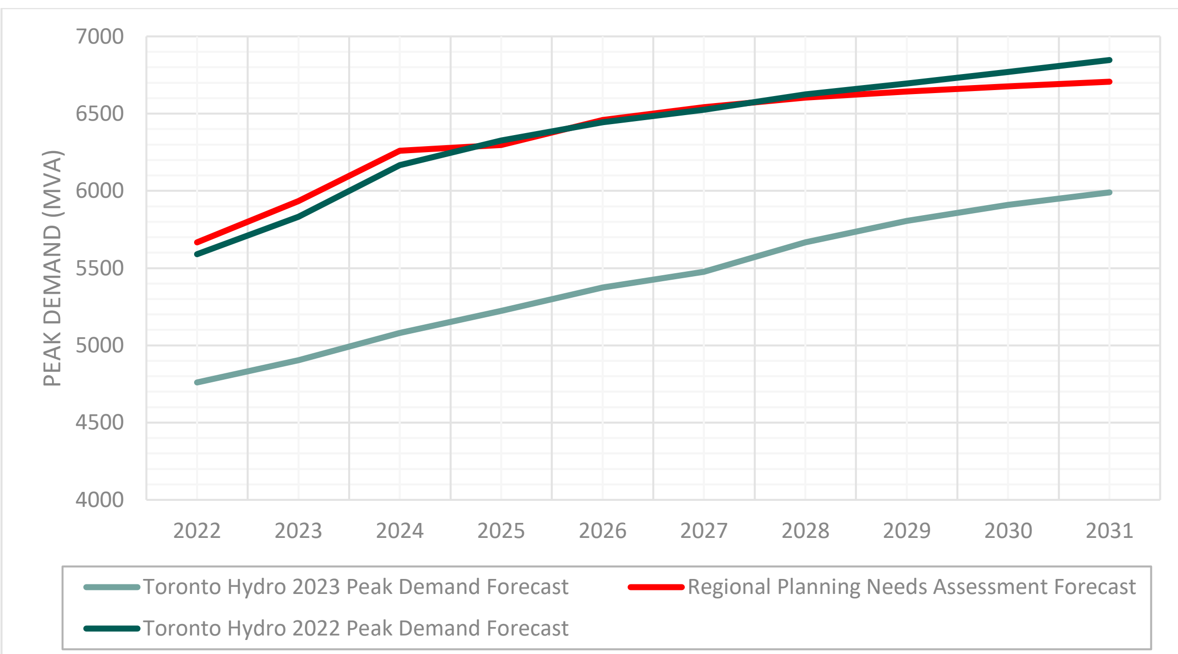

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Figure 3: Toronto Hydro System Peak Demand Forecast and the Regional Planning Needs Assessment Forecast prepared by Hydro One

D4.1.3 Connection Capability

In order to connect new customers, Toronto Hydro needs grid capacity as well as spare feeder positions (i.e. feeder breakers to which new feeders can be connected). As existing feeders reach their capacity, new feeders must be pulled from a station into the distribution system to connect new customers. Although a station may have the capacity to supply the required demand, if there are no feeder positions to connect new feeders to the station, the station is unable to support new connections. To this end, Toronto Hydro must monitor the number of spare feeder positions at its stations to maintain the ability to connect new customers. When new feeders are needed and there are spare feeder positions are available, Toronto Hydro initiates projects in the Load Demand program to transfer feeder loads and free up feeder positions so that new customers can connect to the system in a timely and efficient manner.

D4.1.4 Generation Capacity and Capability Assessment

Toronto Hydro connects DERs to the distribution system in alignment with the Distribution System Code and in coordination with Hydro One Networks and the IESO. As part of its capacity planning process, the utility identified a number of constraints that impact DER connections to the distribution grid, including:

- limited breaker and station equipment capacity due to short circuit capacity constraints;
- reverse power flow limitations based on transformer thermal capacity and minimum load requirements;
- anti-islanding conditions for DG; and
- system thermal limits and load transfer capability.

Short circuit capacity constraints on station equipment are the primary constraint for DER connections. To determine the short circuit capacity at stations and other locations on the distribution system, Toronto Hydro employs sophisticated fault and power flow simulation models. These models predict how much fault current will flow to a specific location from generators located throughout the distribution system. The presence of DERs on distribution feeders can contribute to fault current that can cause station equipment, such as circuit breakers, to exceed short circuit capacity limits. Toronto Hydro completes a study for each new DER application to monitor the available existing short circuit capacity of the system.

D4.2 Capacity Planning and the Energy Transition

The decarbonization of the energy system to mitigate the existential and economic impacts of climate change is expected to create new roles for electricity, including powering transportation and building systems. Toronto Hydro recognizes that the pace and timing of these changes are driven by a complex interplay of policy, technological developments and consumer choice. While there is certainty that fundamental change is ahead, there are degrees of uncertainty about how that change will unfold (e.g. the pace and adoption of EVs and heat pumps; the role of low emission gas; and the scale of local vs. bulk electricity supply). To contend with this uncertainty and complexity in its planning process, Toronto Hydro developed the Future Energy Scenarios modelling tool to understand possible changes to future peak demand under different scenarios. For more information about this tool please refer to Appendix A.

In order to be able to continue to deliver its central purpose of serving the electricity needs of the residents, businesses and institutions in the City of Toronto, the utility must take responsible actions in the 2025-2029 plan period to prepare the local grid and its operations for the unprecedented energy transition that is and will continue to gradually unfold across the economy. At the same time, the exact path and pace of the energy transition remains subject to various factors of uncertainty (policy, technology and consumer behavior), which means that Toronto Hydro must be careful to ensure that investments being made in the 2025-2029 rate period provide long-term value to customers and enable policy, technology and customer choice in effecting the energy transition. To balance both of these objectives, Toronto Hydro adopted a "least regrets" planning philosophy. The term "least regrets" refers to a strategic planning approach anchored in the decision-making theory of anticipating and minimizing regretful choices/outcomes when faced with uncertainty.

As part of its capacity planning process, Toronto Hydro took the following actions to identify least regrets investments in the 2025-2029 rate period:

- included additional drivers in its System Peak Demand Forecast (e.g. EVs, data centers and Municipal Energy Plans) to assess the anticipated future demand;
- augmented its decision-making process with the results of a Future Energy Scenarios model to understand the impact of different policy, technology and consumer behavior drivers; and
- used the Future Energy Scenarios to stress-test whether the utility's capacity plan can accommodate energy transition needs (e.g. building heating electrification) in the early part of the next decade, if required.

The Future Energy Scenarios reveal that the impact of building electrification in the next two decades could be significant from a system peak demand perspective, but that there are notable differences (driven by policy, technology and consumer-behaviour choices) as to when and how building electrification could unfold. For example, the Consumer Transformation scenario of the Future

Energy Scenario shows that localized consumer-focused technology solutions such DERs (including energy efficiency) could materially curtail the annual peak demand curves in a future where buildings are increasingly electrified. In light of these circumstances, "least regrets" meant Toronto Hydro acted with a higher degree of caution in terms of building new capacity to prepare the distribution grid for wide-scale building electrification in the next two decades, as the policy and consumer-behaviour drivers of this type of demand remain uncertain, and technology advancement could offer more cost-effective solutions in the future. Practically, this meant that Toronto Hydro decided to take a "wait and see approach" to investments in new capacity for accommodating wide-scale building electrification in the mid-2030s and beyond.

Toronto Hydro's "least regrets" investment approach to growth and electrification is reinforced by the utility's Grid Modernization strategy summarized in Exhibit 2B, Section D5.

Toronto Hydro's traditional grid infrastructure is facing a shift driven by renewable energy integration, technology evolution, changing customer needs, and more. The Grid Modernization Strategy recognizes the need to prepare for these transformations by transitioning towards a more technologically advanced distribution system, and developing advanced capabilities that over time will provide greater flexibility to:

- take a "wait and see" approach to capital investment needs that have a higher degree of uncertainty, and
- implement increasingly cost-effective technology-based solutions to address grid needs and deliver reliability, resilience, system security and other valuable customer outcomes as electrification accelerates in the next decade and beyond.

Key elements of this investment strategy include investments in Non-Wires Solutions – such as contracted demand response ("Flexibility Services") and grid-scale renewable-enabling battery energy storage systems ("REBESS") – as well as major investments in the development of a more intelligent grid (e.g. contingency enhancements, and investments in sensors and next generation smart meters that are expected to improve grid observability, and the implementation of grid automation solutions such as FLISR). These modernization investments, once implemented on the grid and integrated into operations, provide Toronto Hydro with an enhanced capability to observe system performance at an asset-level and make real-time (and increasingly automated) operating decisions. Building these capabilities is necessary to improve accuracy and granularity of load forecasting and optimize the capacity and performance of a more heavily utilized grid.

D4.3 Capacity Needs and Investment Plan

As noted above, the primary drivers of capacity need and related investments over the 2025-2029 rate period are: customer connections (included as part of the base forecast), electrification of transit, electric vehicles, hyperscale data centers, and Municipal Energy Plans for three regions of the city discussed above. Figure 4 below shows the contribution of each of these drivers to the System Peak Demand Forecast.

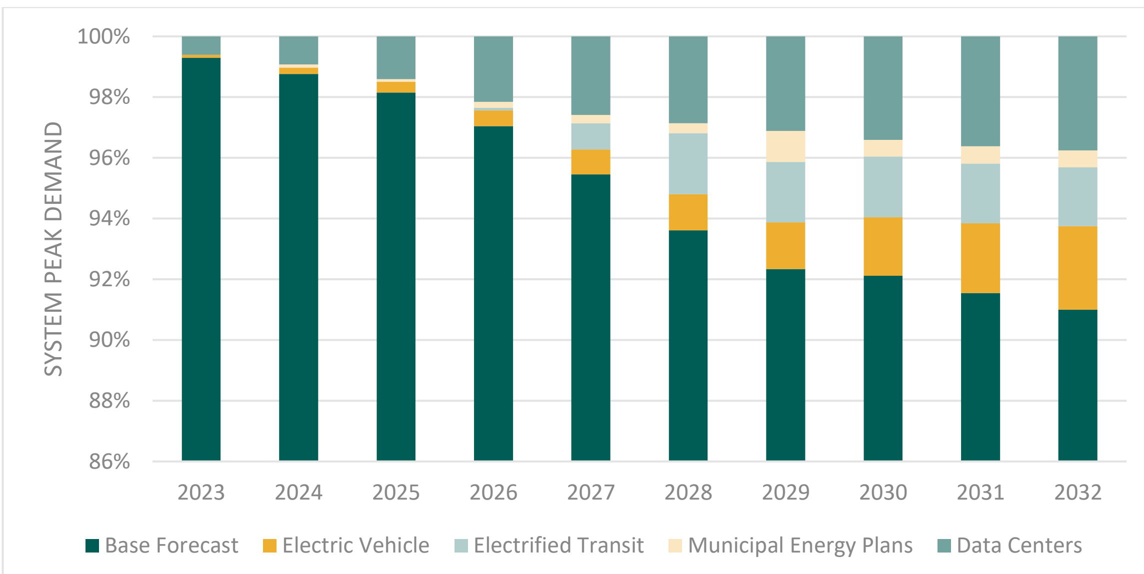

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Figure 4: Toronto Hydro System Peak Demand Forecast by Driver

In the development of the 2022 System Peak Demand Forecast, Toronto Hydro determined that building electrification (i.e. electrification of space and water heating) is not yet a significant driver of growth in the 2025-2029 rate period. As a result, the System Peak Demand Forecast continues to be a summer peaking forecast. However, to stress test the assumptions regarding building electrification against the least regrets planning philosophy, Toronto Hydro assessed whether the utility could accommodate a growing winter peak (driven by building electrification) in the 2025-2029 rate period if needed. To that end, the utility looked at scenarios of forecasted building heating loads derived from the Future Energy Scenario model outputs. More specifically, Toronto Hydro used the Consumer Transformation scenario, and its low efficiency equivalent, as the lower and upper bounds, of the sensitivity test.

The Consumer Transformation scenario models an energy transition pathway where consumers play a prominent role in driving results towards decarbonization. In addition to high levels of transportation electrification, there are high levels of heating electrification, energy efficiency and DERs. In the related low efficiency Consumer Transformation scenario, the uptake of electrified heat and transport technologies is the same, but the uptake of efficiency measures (e.g. building retrofits), and DERs (e.g. renewables and energy storage) is limited, resulting in a higher peak demand. Toronto Hydro selected the Consumer Transformation scenario and its low efficiency equivalent for this sensitivity analysis because these scenarios presented (i) the most variability in building heat, between the high and low efficiency assumptions, and (ii) the most material grid impact of the energy transition in terms of system peak demand.

Figure 5 below compares the Regional Planning Needs Assessment Forecast, the 2022 System Peak Demand Forecasts and the selected upper and lower bounds of the Consumer Transformation scenario. Figure 5 also overlays the 2023 System Peak Demand Forecast, which as noted above, is based on 2022 actuals. The FES scenarios were conducted on the basis of 2021 actuals. Toronto Hydro expects that if the FES scenarios were updated for 2022 actuals the relativity of the FES curves to the 2023 Peak Demand Forecast would be roughly similar.

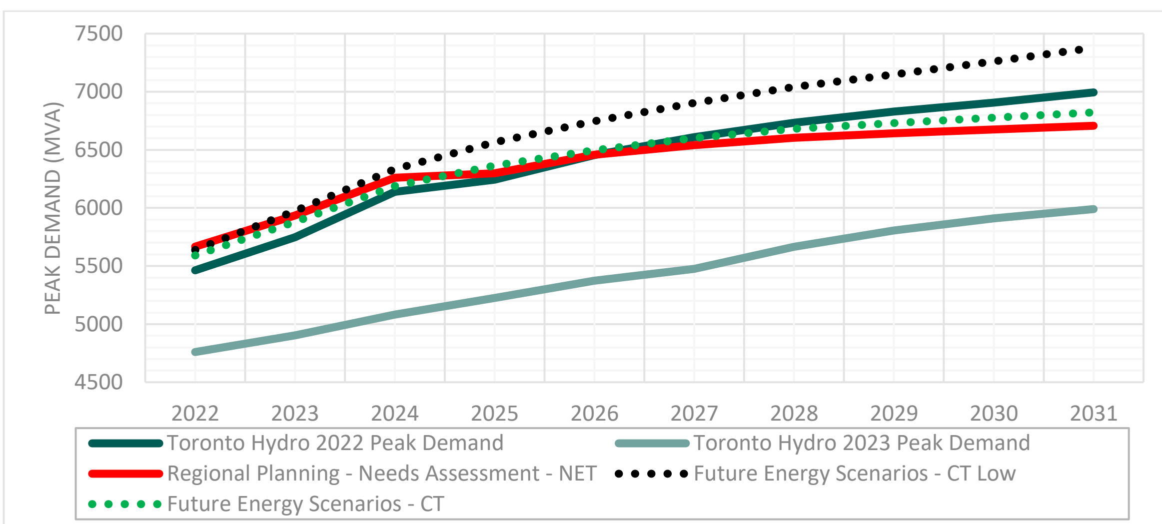

Figure 5: Comparison of Planning Forecasts and Future Energy Scenarios

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As shown in Figure 5 above, Toronto Hydro's 2022 System Peak Demand Forecast is generally aligned with the Consumer Transformation (CT) scenario. From this analysis, Toronto Hydro concluded that the capacity investment plan can meet higher levels of building heating loads (which contribute to /C winter peak) should this driver of electrification materialize at a faster pace than expected. As a result, Toronto Hydro has confidence that the investments in system capacity that the utility proposes to make in the 2025-2029 rate period are least regrets to address growth and electrification drivers that the utility faces in this decade and the early part of the next decade. That being said, it is possible that the utility could be faced with incremental capacity constraints at a localized level as a result of accelerated transportation and building electrification demand. To address this challenge, the utility proposes a Demand Related Variance Account to track variances in actual versus forecasted expenditures in a number of demand-related investment programs. For more information about this proposal please refer to Exhibit 1B, Tab 2, Schedule 1.

Based on the capacity planning process outlined above, Toronto Hydro proposes investments in various programs to meet the utility's fundamental obligation to connect new and expanded services to the grid in this decade and beyond. These programs include expansion to increase grid capacity and enhancements to better utilize existing equipment. Through programs such as Load Demand[6], Stations Expansion[7], and Horseshoe and Downtown Renewal[8], Toronto Hydro is renewing and enhancing stations, buses, feeders, and other equipment that will facilitate load growth at the appropriate locations. In areas where Toronto Hydro expects customers to connect more DERs, programs such as Grid Protection, Monitoring and Control alleviate short-circuit capacity constraints.[9] Furthermore, where feasible and cost-effective, Toronto Hydro's intends to leverage the Non-Wires Solutions program to (i) procure market-based flexibility services to avoid or defer capital investment, and (ii) deploy grid-scale storage solutions to enable the connection of renewable energy generation facilities.[10]

The sections that follow discuss in more detail the capacity investments that Toronto Hydro intends to make in key areas of the grid.

D4.3.1 Downtown Area

Figure 6 below shows all transformer stations in the Downtown area. Areas in green represent transformer stations that do not require relief within 10 years. The transformer stations in yellow

[6] Exhibit 2B, Section E5.3
[7] Exhibit 2B, Section E7.4
[8] Exhibit 2B, Section E6.2 and Section E6.3
[9] Exhibit 2B, Section E5.5.
[10] Exhibit 2B, Section E7.2.

require bus relief between 5 to 10 years while the transformer stations in red, require bus relief within 5 years.

Immediate relief to the midtown region in red is planned to be achieved through expansion and renewal work at Bridgman TS and Duplex TS, and through load transfers from Bridgman TS to Wiltshire TS. For more information please refer to Exhibit 2B, Sections E7.4 and E5.3.

The south west region of the downtown core, served by Copeland, Cecil and Strachan TS could become capacity-constrained before the end of the decade. While Copeland TS - Phase 2 introduces increased system capacity and spare feeder positions to the downtown core, it is expected to be constrained by 2032. The Load Demand and Flexibility Services programs addresses capacity limitations at these stations in the short term through station bus load transfers and demand response activities.

Incremental relief to Main TS and Strachan TS is planned to be achieved through switchgear and transformer replacements. For more information please refer to Exhibit 2B, Section E7.4.

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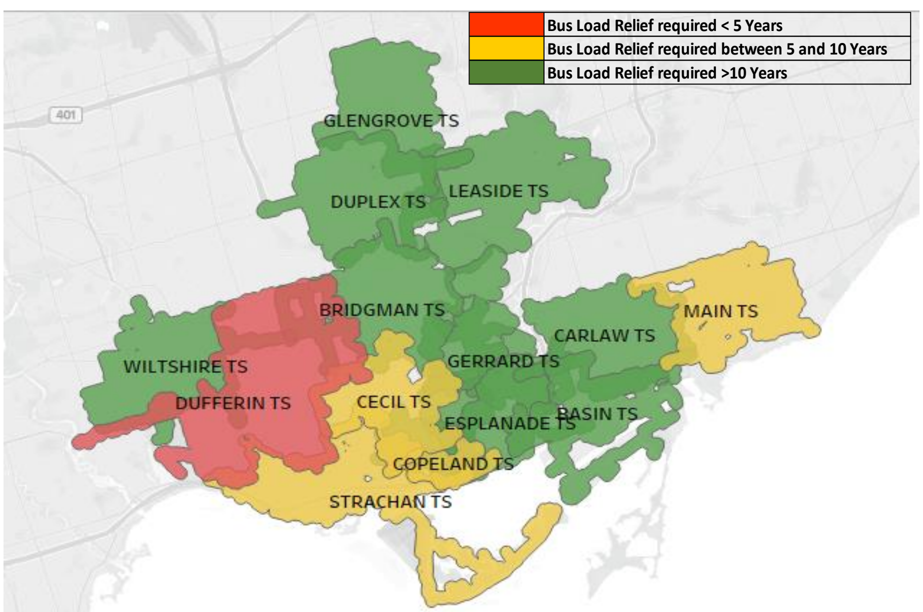

Figure 6: Downtown stations requiring load relief

D4.3.2 Horseshoe East Area

The Scarborough area in the Horseshoe East experienced significant load growth in recent years, and Toronto Hydro expects this trend to persist due to the development of the Golden Mile corridor, the Ontario Line, and the Scarborough subway extension. In particular, the Golden Mile Secondary Development Plan covers an area of 113 hectares of land in Scarborough bordered by Ashtonbee Road to the north, Birchmount Road to the east, Civic Road / Alvinston Road to the south and Victoria Park Avenue to the west. Taking these drivers into account, Toronto Hydro forecasts average growth of 3.0% per year over the next 10 years in the Horseshoe East Area. The System Peak Demand Forecast shows that the area is not expected to reach 90% of its capacity before 2031. The Horseshoe East Area is forecasted to experience a lack of feeder positions by 2032. This constraint is particularly acute at Warden TS and Ellesmere TS. However, Toronto Hydro notes that while Scarborough TS can provide relief to these stations in the short-term, increased demand in the Scarborough area due to continued development and electrification could drive the need for investment at Scarborough TS over the 2025-2029 rate period. Figure 7 highlights the load relief required in the short term. Toronto Hydro plans to provide capacity relief to the area by increasing the transformer size at Scarborough TS in the 2025-2029 rate period. The utility is also monitoring peak demand in the area for accelerated growth that could trigger additional investments in the 2025-2029 rate period.

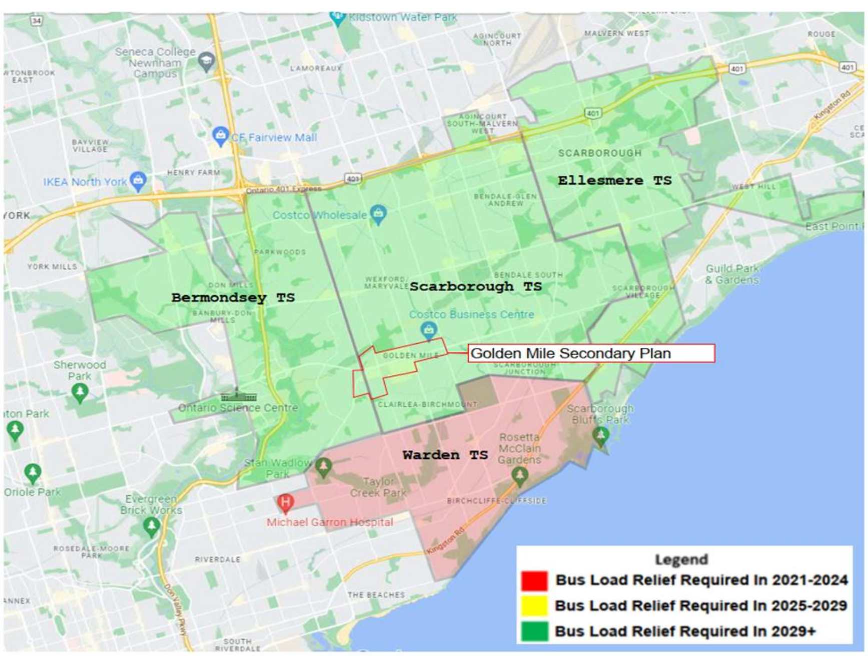

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Figure 7: Scarborough TS and East Region

D4.3.3 Horseshoe West Area

The Horseshoe West is also expected to experience notable load growth over the next decade, resulting in a forecasted average peak demand growth of 2.8% per annum. The System Peak Demand Forecast indicates that the majority of stations in this area are expected to reach capacity in the next decade or shortly thereafter. Moreover, by the end of the decade, Toronto Hydro forecasts the entire area to be highly loaded. The region surrounding the Downsview area (shown in Figure 8 below) is expected to see the highest growth due to redevelopment of this area.

In 2017, the City of Toronto approved of the Downsview Area Secondary Plan, covering 210 hectares, bounded by Sheppard Avenue to the north, Allen Road to the east, Wilson Avenue to the south, and Downsview Park and the Park Commons to the west, as shown in Figure 9.

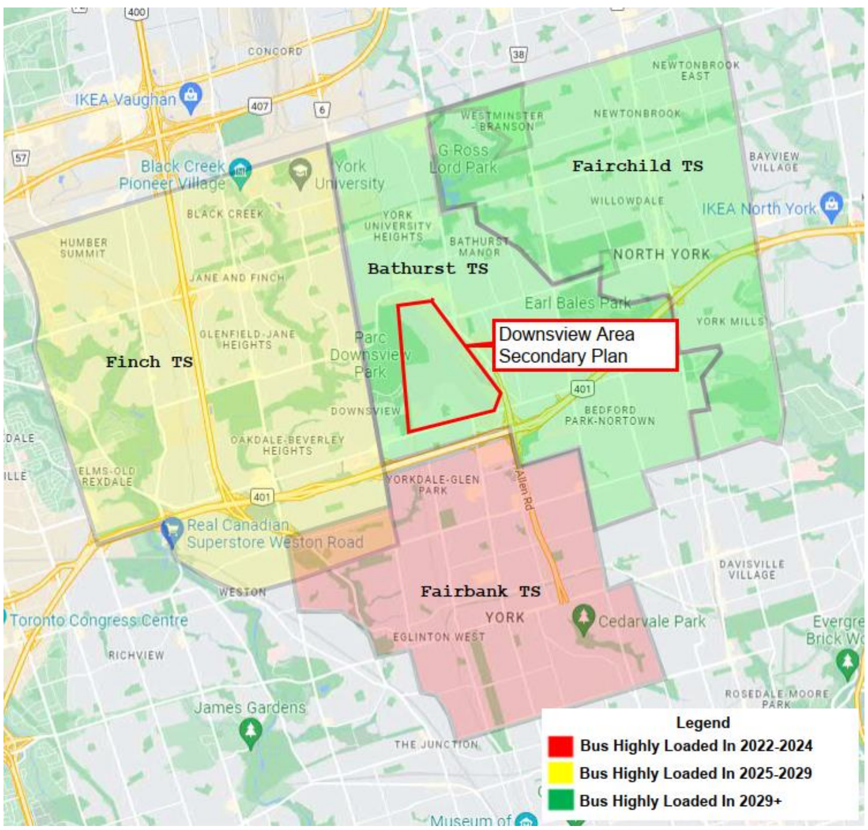

Figure 8: Downsview Area and surrounding stations

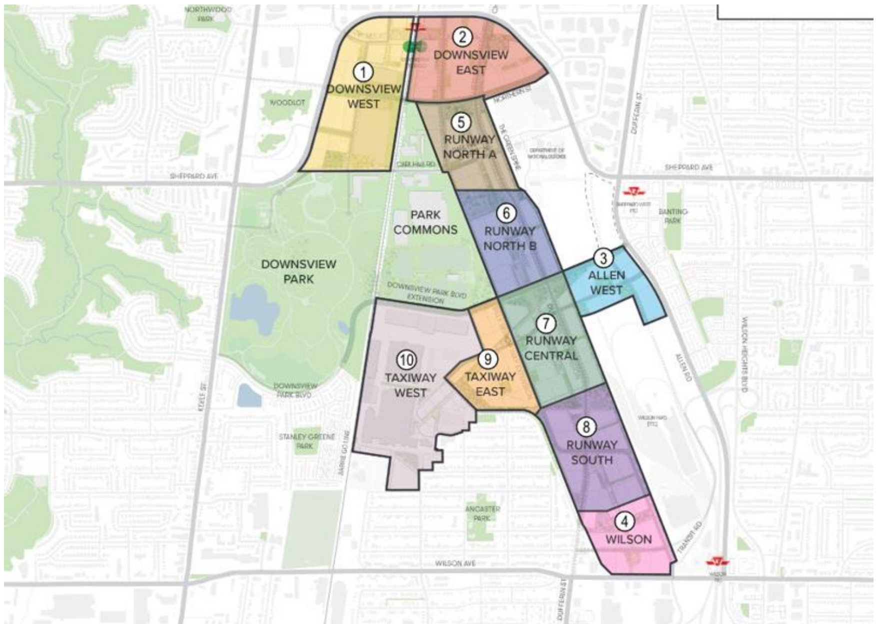

Figure 9: Downsview Area Secondary Plan

The Downsview Area Secondary Plan includes plans to expand each district with a mix of commercial, office, industrial and institutional buildings. The Allen East District is planned for a residential development of approximately 3,500 dwelling units. Load in the Downsview area is expected to reach 103 MW by 2029, 180 MW by 2034, and 509 MW by 2051.[11] Based on this growth, load relief is needed at a regional level to support rising demand due to development and electrification in the Horseshoe West area. Through the Toronto Regional Planning process, the utility proposes to construct a new transformer station (Downsview TS) to address this need. Please refer to the Stations Expansion Program at Exhibit 2B, Section E7.4 for more information.

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[11] Exhibit 2B, Section E7.4.3.1 – Downsview TS.

E3 System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources

This section provides information on the capability of Toronto Hydro's distribution system to accommodate renewable energy generation and other distributed energy resource ("DER") connections. This information includes renewable DER applications, overall DER connection projections, the distribution system's ability to connect, as well as known constraints on the distribution system.

E3.1 DER Applications

Since the introduction of the *Green Energy and Green Economy Act, 2009*, Toronto Hydro connected over 2400 DERs under various programs including FIT, HCI, PSUI-CDM, RESOP, HESOP,[1] and Net-Metering. In 2018, the FIT and micro FIT programs ended, and the *Green Energy and Green Economy Act, 2009* was repealed on January 1, 2019. Interest in generation projects within Toronto Hydro's service territory saw a greater than anticipated decrease in renewable pre-assessment applications in the years immediately following the conclusion of the FIT program in 2018. However, customers have continued to show an interest in DER projects, and connections continue to grow, albeit at a slower pace. Toronto Hydro continues to receive applications from a wide range of proponents including, but not limited to, individual residential addresses, public transit facilities, housing developments, large grocery stores, educational facilities, and hospitals.

As of the end of 2022, Toronto Hydro has 2,424 unique DER connections to its distribution grid. Figure 1 provides an overview of existing DER connections within Toronto Hydro's service territory. This represents over 304.9 MW of generation capacity across various types of DER technologies.

[1] Feed-in Tariff ("FIT"); Hydroelectric Contract Initiative ("HCI"); Process and Systems Upgrade Initiative – Conservation Demand Management (PSUI-CDM"); Renewable Energy Standard Offer Program ("RESOP"); and Hydroelectric Standard Offer Program ("HESOP");

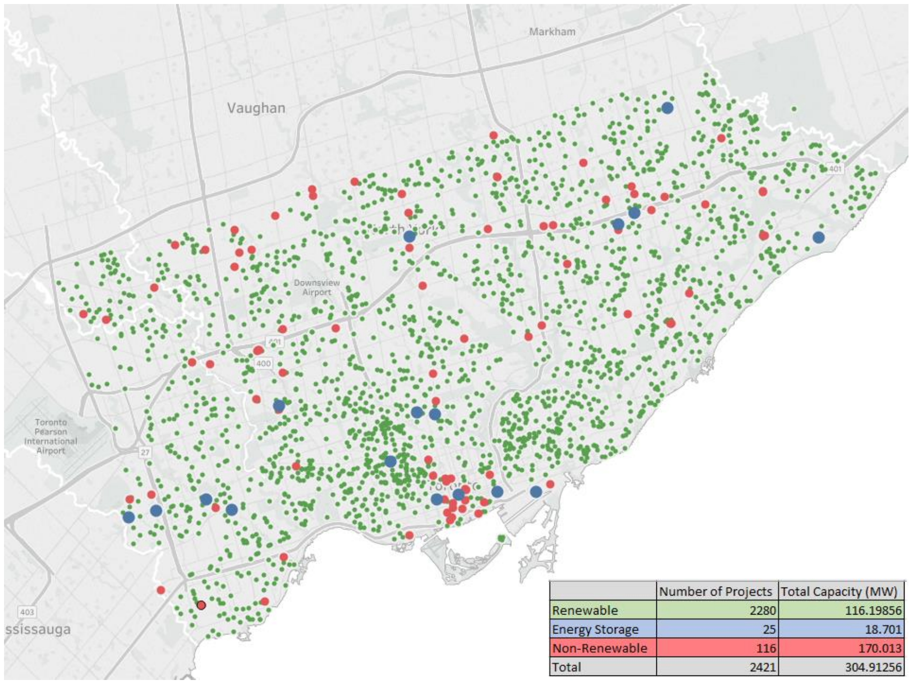

Figure 1: Toronto Hydro DG Connections (as of December 31st, 2022)

From 2018 to 2022, Toronto Hydro connected about 93.2 MW of generation to its distribution system, which represents approximately 22.8 percent of the 408.4 MW connected capacity that was projected for the same time period in the 2020-2024 rate application. The lower than expected DER capacity connected during this period can be attributed to various reasons:

- The conclusion of the FIT program in 2018 led to a greater than anticipated decrease with a 71.9 percent decline in renewable DER pre-assessment applications in the years immediately following the cancellation across residential, commercial & industrial segments.
- Changes in the IESO Process Systems & Upgrade program in 2019 made fossil-fuel based CHP projects ineligible for incentives.
- During the COVID-19 pandemic there was a sharp reduction in applications for pre-assessments for DERs by commercial and industrial businesses. Subsequently, connections fell well below pre-pandemic expectations.
- A number of large projects were placed on hold indefinitely by customers or were cancelled, including, but not limited to, a 9.87 MW biogas generator project, a 15 MW energy storage system, and a 10 MW diesel synchronous generator project.

E3.2 Forecasted DER Connections

Toronto Hydro's 2023-2029 DER connection and capacity forecast considers a combination of historical trends, project pipeline, economic environment and the current energy policies at the time of the forecast.[2] Total DER projects are expected to contribute a total increase of 67 percent to total installations, reaching nearly 4,500 connections by the end of 2029, as shown in Figure 2. This represents a total DER installed capacity of approximately 516.7 MW by the end of 2029 in comparison to the 304.9 MW installed as of the end of December 2022, depicted in Figure 3.

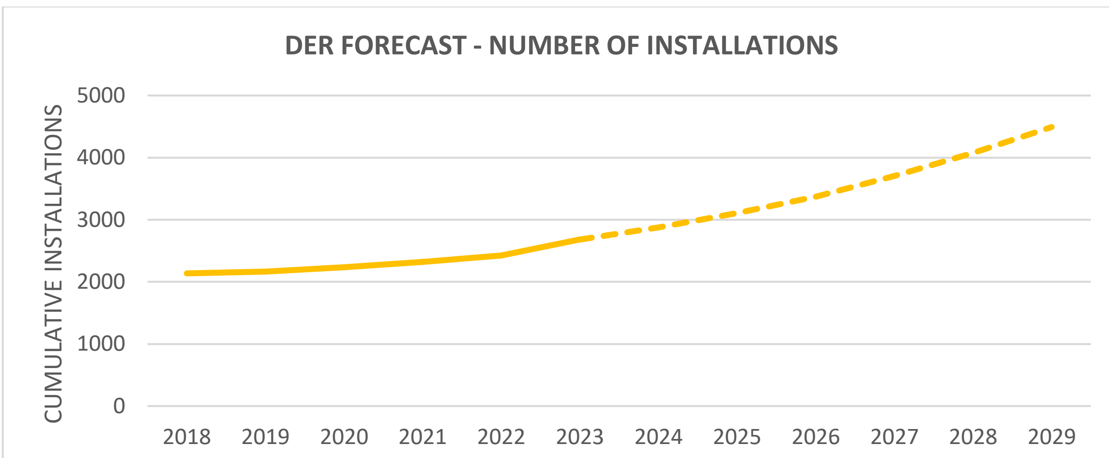

Figure 2: Historical and Forecasted DER Installations

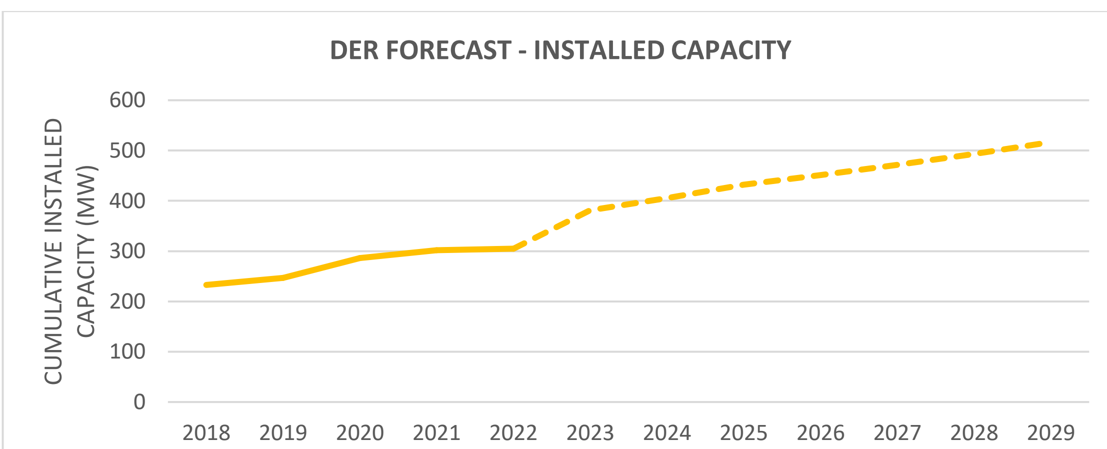

Figure 3: Historical and Forecasted Installed DER Capacity

[2] See Exhibit 2B, Section E5.1.3.2 for further details of Toronto Hydro's DER connection forecast methodology.

Toronto Hydro organizes its DER forecast into renewable, energy storage and non-renewable categories. As of the end of 2022, renewable installations represent the largest category of DER by number of connections while non-renewables represent the largest category by generation capacity. Non-renewable DERs are generally larger capacity connections used to support large commercial or industrial facilities. With more emphasis on decarbonization, it is expected that the combined installed capacity for renewable and energy storage facilities could surpass non-renewables by 2029 as shown in Figure 4.

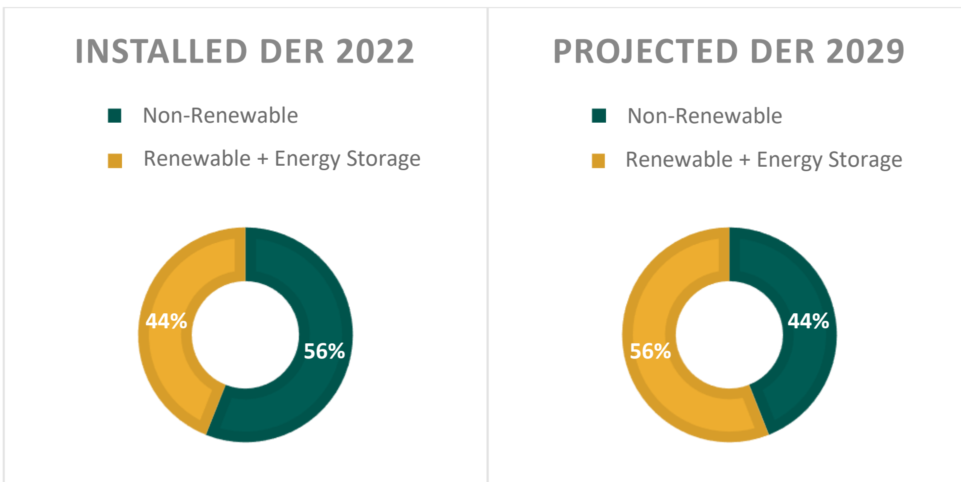

Figure 4: DER Composition by Installed Capacity

E3.2.1 Forecasted Connections for Renewable

Between 2023 and 2029, Toronto Hydro forecasts over 1700 additional renewable connections (totalling over 74 MW) to the distribution system. This would bring total installed capacity to approximately 200 MW as shown in Figure 5. This rate of growth is in alignment with the Ontario Distributed Energy Resources Impact Study conducted by ICF and submitted to the OEB in 2021.[3]

[3] Ontario Energy Board, ICF, Ontario DER Impact Study (January 18, 2021), online, https://www.oeb.ca/sites/default/files/ICF-DER-impact-study-20210118.pdf

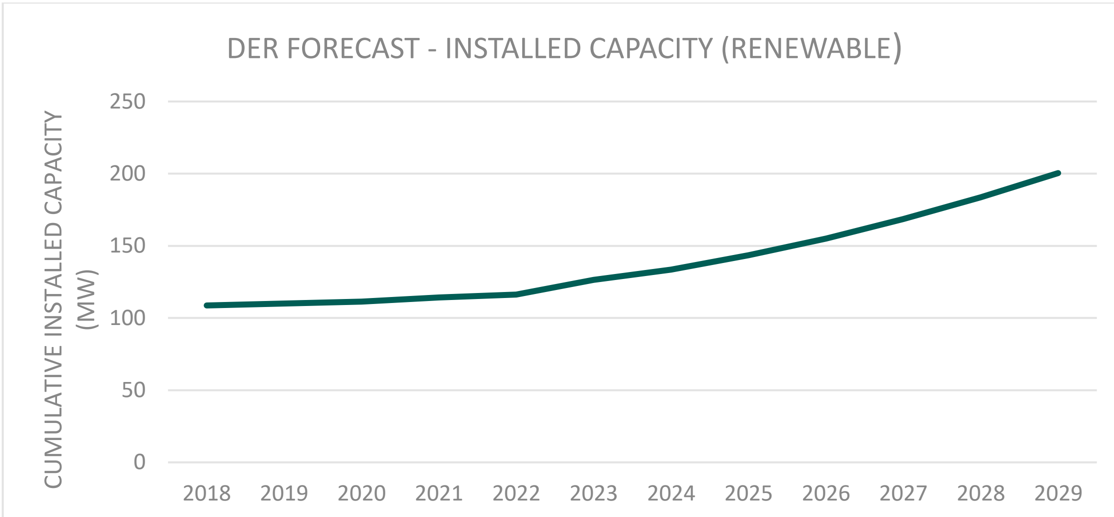

Figure 5: Historical and Forecasted Renewable DER Installed Capacity

E3.2.2 Forecasted Connections for Energy Storage

Although in recent years Toronto Hydro saw a reduced interest in energy storage projects, the utility forecasts a return to high growth by the end of decade. As of the end of 2022, Toronto Hydro connected 28 energy storage projects with total generating capacity of 18.7 MW, the vast majority of which are used in commercial and industrial applications, including for the reduction of global adjustment charges. Toronto Hydro's current energy storage project pipeline anticipates the connection of 12 projects by the end of the year with a combined capacity of 31.9 MW.

Beyond 2025, Toronto Hydro expects that energy storage growth will return to linear growth patterns, similar to pre-pandemic levels. Between 2023 and 2029, Toronto Hydro forecasts over 50 additional energy storage connections (totalling over 70.8 MW) to the distribution system. This would increase the total number of connections to 82 by 2029, and the total installed energy storage capacity to 89.5 MW, as depicted in Figure 6.

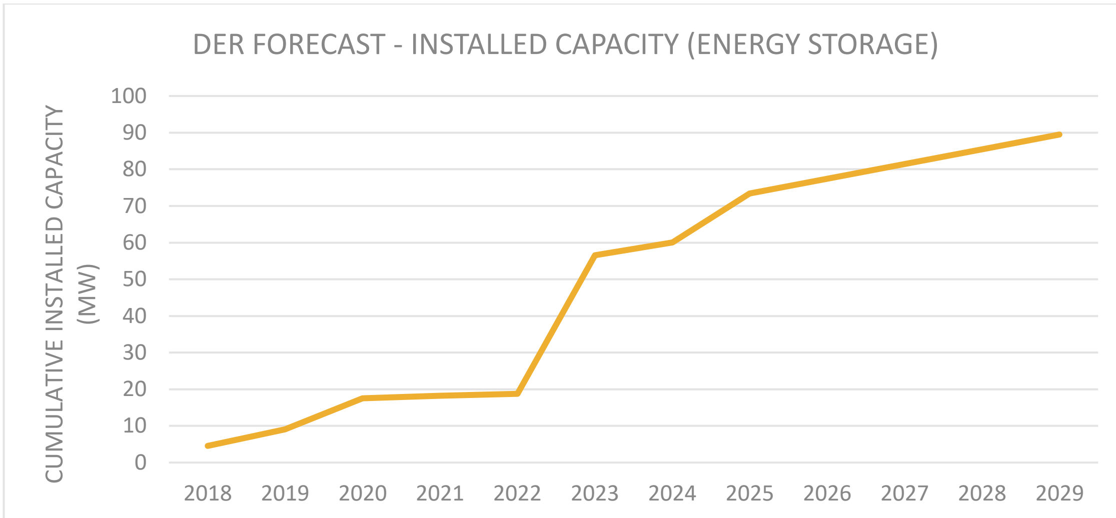

Figure 6: Historical and Forecasted Energy Storage Capacity

E3.2.3 Policy Considerations

Customer choice is the key driver of DER demand, and this driver can be greatly impacted by policy, including the available funding and incentives. The FIT program is a testament to the significant impact that policy and incentives can have on the renewable DER uptake by customers. Between 2009 and 2018 when the FIT program was active, DER installed capacity increased from 1.4 MW to 108.7 MW—a compound annual growth rate of 62.2 percent. When the FIT program ended, the renewable energy annual average growth rate fell to 1.7 percent over 2018 to 2022.

Policies and economic factors that may impact the rate of renewables and energy storage connections include:

- **Green Energy Tax Credit –** Announced by the Federal Government in November 2022, the Green Energy Tax Credit is a refundable credit of up to 30 percent of the capital cost of investments in specific generation systems, including solar PV and battery storage systems.[4]
- **Third Party Ownership of Net Metered Generation Facilities –** On July 1, 2022, the OEB enacted changes to enable third-party ownership of Net Metered generation facilities,

[4] Environment and Climate Change Canada, Clean Investment Tax Credits in Budget 2023, "online", https://www.canada.ca/en/environment-climate-change/news/2023/04/minister-guilbeault-highlights-the-big-five-new-clean-investment-tax-credits-in-budget-2023-to-support-sustainable-made-in-canada-clean-economy.html

opening up access to the program for customers who may not be in a position to own or operate their own behind-the-meter renewable energy generating equipment.[5]

- **Lithium Ion Battery Cost** – Lithium Ion battery prices have decreased by more than 79 percent since 2013 and are expected to continue to decrease.[6] The combination of solar PV and energy storage allows users to maximize the use of solar PV generated energy that can only be captured during the day.
- **Ultra-Low Overnight Price Plan** – In 2023, Ontario launched an "Ultra-Low" (ULO) overnight price plan for residential and small business customers. The ULO plan offers an overnight rate of 2.4 cents per kWh (down from 7.4 cents)[7] providing an incentive for storing energy overnight and discharge it during the day when the price is higher.
- **Industrial Conservation Initiative (ICI) program** – Commercial and industrial customers who opt into the Industrial Conservation Initiative (ICI) program can reduce their global adjustment charges through peak shaving using energy storage systems.

The timing, impact and probability of customer demand is subject to a host of policy, economic and technology factors that are difficult to predict. While Toronto Hydro considered the programs and incentives that are currently available to customers in preparing its DER forecast, actual growth rates could materially differ from what the forecast anticipates if new programs or incentives become available.[8] As such, the utility needs flexibility to adapt its plans in response to external factors which could drive up greater customer demand for renewables or energy storage. To enable this flexibility over the 2025-2029 rate period, Toronto Hydro's Custom Rate Framework proposes a mechanism known as the Demand Related Variance Account (DRVA). For more information about the DRVA, please refer to Exhibit 1B, Tab 2, Schedule 1.

[5] Ontario Energy Board, Forms and Templates: Third-Party Net Metering and Energy Contracts , "online", https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/forms-and-templates-third-party-net

[6] BloombergNEF, Lithium-ion Battery Pack Prices Rise for First Time to an Average of $151/kWh, "online", https://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/#:~:text=LFP%20battery%20pack%20prices%20rose,cell%20prices%20observed%20in%202022

[7] https://news.ontario.ca/en/release/1002916/ontario-launches-new-ultra-low-overnight-electricity-price-plan

[8] See, for example, the Future Energy Scenarios Report where consumer choice modelling of the uptake scenarios for rooftop solar PV showed a range of installed capacity by 2050 of between 400 MW to 1,200 MW; Exhibit 2B, Section D4, Appendix B – *Future Energy Scenarios Report* at pages 67-70.

E3.2.4 Forecasted Connections for Non-Renewable

Toronto Hydro's pipeline for non-renewable DER currently consists of 8 projects, totalling 26.6 MW expected to be connected in 2023. Between 2023 and 2029, Toronto Hydro forecasts 28 additional non-renewable DER connections (totalling over 56.8 MW) to the distribution system. This would bring total installed non-renewable DER capacity to 226.8 MW as shown in Figure 7.

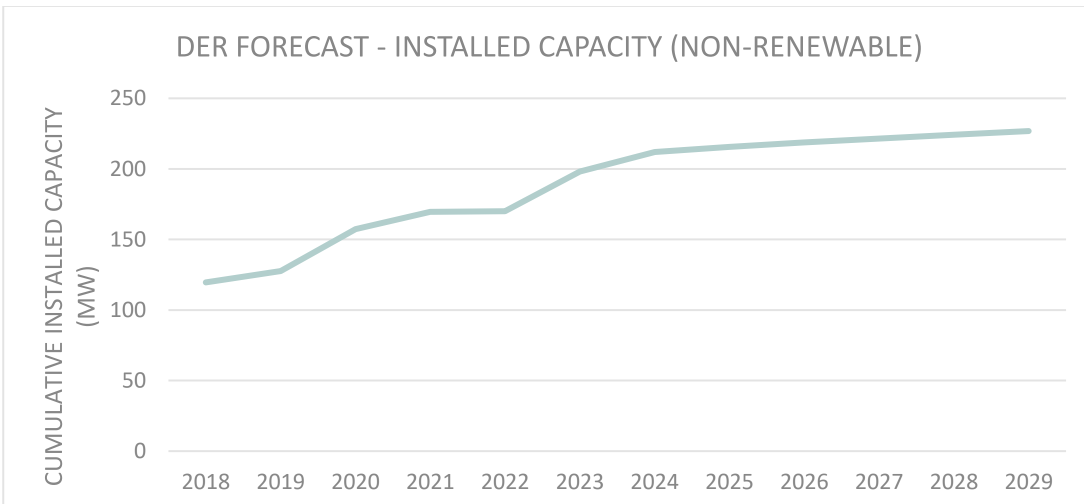

Figure 7: Historical and Forecasted Non-Renewable Capacity

While Toronto Hydro anticipates government policy to gradually reduce the use of non-renewable sources of energy in the journey to reaching net zero goals, the most common applications of non-renewable DER do not yet have viable or technologically mature alternatives. For example, gas generators remain a preferred method of backup generation as they can run for long periods of time in the event of a prolonged outage. Non-renewable generation is also used for Combined Heat and Power (CHP) systems which can generate both heat and electricity.

E3.3 System Capability to Connect DER

Toronto Hydro's system capability to connect renewable DER facilities is subject to a number of considerations, including short-circuit capacity, the risk of islanding, thermal limits, and the inability to transfer loads between feeders during planned work. Each of these considerations is described in greater detail below.

1. Short Circuit Capacity Constraints

To maintain safe and reliable operation of the distribution system, Toronto Hydro cannot connect DERs in situations where short circuit capacity limitations exist. Short circuit capacity is electrical system or component's capacity to withstand without permanent damage, high levels of electrical energy congregating on that point or location. Figure 8 below is a map which shows the areas within Toronto's grid that are approaching, or have reached, short circuit limits at various stations. These stations are supplied by Hydro One Networks Inc. transformers and directly connect to Toronto Hydro feeders.

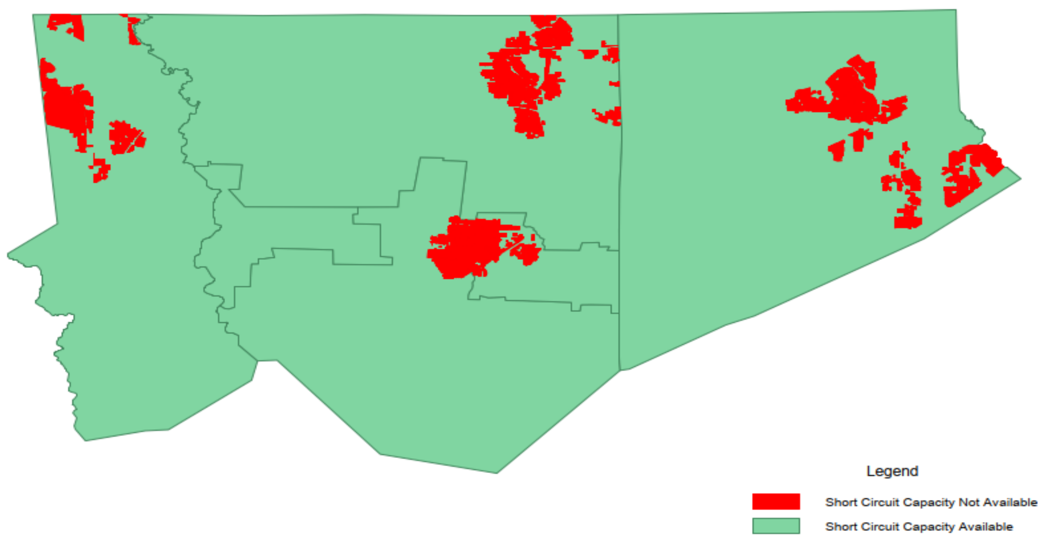

Figure 8: Map of Distribution System Short Circuit Capacity Constraints

Toronto Hydro maintains a list of restricted feeders on its website that is updated every 3 months in accordance with section 6.2.3 (g) of the Distribution System Code. As of July 2023, Toronto Hydro has five transformer station bus pairs that are restricted leading to 48 total restricted feeders due short circuit capacity constraints, as outlined in Table 1 below.

Table 1: Restricted Feeders and Number of Connected Customers

Station Name	Feeder Designation	Restriction	No. of Connected Customers
Sheppard TS, Bus EZ	47-M4	Short Circuit Capacity	0
	47-M6	Short Circuit Capacity	3378
	47-M1	Short Circuit Capacity	3952

Station Name	Feeder Designation	Restriction	No. of Connected Customers
	47-M5	Short Circuit Capacity	0
	47-M2	Short Circuit Capacity	0
	47-M8	Short Circuit Capacity	618
	47-M7	Short Circuit Capacity	1293
	47-M3	Short Circuit Capacity	5909
Woodbridge TS, Bus BY	D6-M1	Short Circuit Capacity	662
	D6-M2	Short Circuit Capacity	0
	D6-M3	Short Circuit Capacity	0
	D6-M4	Short Circuit Capacity	322
	D6-M5	Short Circuit Capacity	0
	D6-M6	Short Circuit Capacity	0
Leslie TS, Bus BY	51-M1	Short Circuit Capacity	0
	51-M3	Short Circuit Capacity	1794
	51-M5	Short Circuit Capacity	1065
	51-M7	Short Circuit Capacity	5663
	51-M2	Short Circuit Capacity	0
	51-M4	Short Circuit Capacity	625
	51-M6	Short Circuit Capacity	2196
	51-M8	Short Circuit Capacity	2582
Leaside TS, Bus AQ	A-5-L	Short Circuit Capacity	54
	A-6-L	Short Circuit Capacity	30
	A-10-L	Short Circuit Capacity	65
	A-12-L	Short Circuit Capacity	1990
	A-13-L	Short Circuit Capacity	1934
	A-16-L	Short Circuit Capacity	5
	A-17-L	Short Circuit Capacity	32
	A-21-L	Short Circuit Capacity	2058
	A-22-L	Short Circuit Capacity	2623
	A-26-L	Short Circuit Capacity	34
	A-1-L	Short Circuit Capacity	0
	A-3-L	Short Circuit Capacity	6

Station Name	Feeder Designation	Restriction	No. of Connected Customers
	A-28-L	Short Circuit Capacity	10
	A-2-L	Short Circuit Capacity	0
	A-4-L	Short Circuit Capacity	12
	A-27-L	Short Circuit Capacity	20
	A-14-L	Short Circuit Capacity	2019
Richview TS, Bus BY	88-M1	Short Circuit Capacity	90
	88-M3	Short Circuit Capacity	127
	88-M5	Short Circuit Capacity	0
	88-M7	Short Circuit Capacity	0
	88-M2	Short Circuit Capacity	1651
	88-M4	Short Circuit Capacity	0
	88-M6	Short Circuit Capacity	0
	88-M8	Short Circuit Capacity	49

Toronto Hydro is working with Hydro One to mitigate these restrictions by re-examining feeder limits and making planned investments in bus tie reactors as part of the Generation Protection Monitoring and Control (GPMC) program at Exhibit 2B, Section E5.5.

2. Anti-Islanding Condition for DER

Islanding occurs when a DER source continues to power a portion of the grid even after the main utility supply source has been disconnected or is no longer available. This situation must be avoided as it can interfere with grid protection systems and pose a serious safety risk to crews who perform work on Toronto Hydro's system. To safeguard against this risk, the connection of photovoltaic solar inverters and other DER sources must prevent unintentional islanding, as per IEEE 1547.2/D6.5, August 2023 (Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces).[9] Toronto Hydro plans to continue to deploy real-time monitoring and control investments at every new DG site to protect against the risk of islanding. For more information please refer to the GPMC program at Exhibit 2B, Section E5.5.

[9] "IEEE Draft Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE P1547.2/D6.5, August 2023, vol., no., pp.1-322, 11 Aug. 2023 ("IEEE P1547.2/D6.5").

As the ratio of generation capacity to minimum load on a feeder increases, the amount of time required by inverters to respond to anti-islanding scenarios also increases and the effectiveness of inverter response to anti-islanding scenarios decreases. Based on common industry practice[10] Toronto Hydro aims to ensure that "DR aggregate capacity is less than one-third of the minimum load of the Local Electric Power System (EPS)"[11] – i.e. minimum generation to load ratio (MLGR).

Toronto Hydro conducted an analysis for all feeders in its system to establish MLGR in accordance with applicable guidance found in IEEE-P1547.2/D6.5, August 2023.[12] The results of study, summarized in Table 2 below, show that 23 feeders are below the recommended ratio, and that by 2029 an additional 24 feeders could be below the ratio based on the DER forecast for renewables.

Table 2: MLGR Feeder Analysis

Station	Feeder Name	Nameplate Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Min. Load (MW)	Current MLGR	MLGR Forecast 2029	REG Cx Enabled (MW)
Agincourt TS	63-M6	3.530	100.0%	5.77	7.10	2.011	1.230	2.24
Finch TS	55-M31	1.750	100.0%	2.95	3.52	2.011	1.193	1.20
Fairbank TS	35-M8	1.997	83.0%	2.80	5.50	2.753	1.750	1.15
Rexdale TS	R29-M1	1.115	100.0%	1.94	2.54	2.275	1.305	0.83
Horner TS	R30-M3	0.760	100.0%	1.38	1.91	2.519	1.387	0.62
Scarborough TS	E5-M24	3.712	16.5%	1.15	4.12	1.109	0.969	0.53
Horner TS	R30-M10	4.573	12.5%	1.08	5.12	1.120	1.007	0.51
Bathurst TS	85-M6	6.761	7.5%	0.98	5.56	0.822	0.768	0.47
Bathurst TS	85-M30	5.250	9.5%	0.97	2.83	0.539	0.495	0.47
Finch TS	55-M32	1.508	33.2%	0.97	4.09	2.712	2.069	0.47
Leslie TS	51-M25	1.677	25.5%	0.85	4.88	2.911	2.322	0.43
Finch TS	55-M29	1.914	21.7%	0.83	4.22	2.205	1.809	0.42
Fairchild TS	80-M10	1.300	23.1%	0.65	2.69	2.069	1.629	0.35
Leslie TS	51-M23	2.100	14.3%	0.65	4.58	2.181	1.868	0.35

[10] R. Seguin, et. al., *High-Penetration PV Integration Handbook for Distribution Engineers*, NREL/TP-5D00-63114 (2016), "online", https://www.nrel.gov/docs/fy16osti/63114.pdf
[11] IEEE P1547.2/D6.5.
[12] "IEEE Draft Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE P1547.2/D6.5, August 2023 , vol., no., pp.1-322, 11 Aug. 2023.

Station	Feeder Name	Nameplate Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Min. Load (MW)	Current MLGR	MLGR Forecast 2029	REG Cx Enabled (MW)
Bathurst TS	85-M7	6.105	1.7%	0.34	2.62	0.429	0.413	0.24
Bathurst TS	85-M1	6.013	0.2%	0.20	6.86	1.141	1.107	0.18
Finch TS	55-M2	5.300	0.0%	0.18	2.96	0.558	0.541	0.18
Bathurst TS	85-M32	4.750	0.0%	0.18	6.08	1.280	1.234	0.18
Windsor TS	A-61-WR	1.500	0.0%	0.18	2.75	1.835	1.642	0.18
Esplanade TS	A-39-X	7.000	0.0%	0.18	14.50	2.072	2.021	0.18
George Duke TS	A-45-GD	1.050	0.0%	0.18	2.18	2.074	1.776	0.18
Fairchild TS	80-M23	0.900	0.0%	0.18	2.12	2.356	1.970	0.18
Cecil TS	A-41-CE	1.275	0.0%	0.18	3.37	2.646	2.326	0.18

To address islanding concerns and enable safe connection of renewable DERs on feeders with a high generation to load ratio, an energy storage system (ESS) can be installed on the feeder to act as a load to manage MLGR when the minimum load is low. For more information, please refer to the Renewable Battery Energy Storage System segment of the Non-Wires Solutions program at Exhibit 2B, Section E7.2.

3. System Thermal Limits and Load Transfer Capability

For large generation, or aggregated generation, an important operating limit stems from a feeder's continuous load thermal ratings. Exceeding system thermal limits adversely affects the lifespan of distribution equipment and can cause immediate equipment failure. Monitoring and control equipment allows Toronto Hydro to monitor and mitigate feeder thermal loading.

In undertaking feeder planning and operations, Toronto Hydro considers the system impact of the generator being online versus offline. The aforementioned thermal ratings affect the variability of various generation sources, system load growth, and the occurrence of contingencies, as thermal limits are indicative of the grid's equipment withstand capabilities. Since contingencies and feeder planned work occur particularly on feeder load transfers, it is imperative to assess the relative impact DER would impose particularly those larger capacity generators. Real-time monitoring and control would provide this window of information.

E3.3.1 Planned Investments to Eliminate Constraints

In order to connect the forecasted DERs to Toronto Hydro's distribution system, the following solutions have been identified as planned investments for the 2025 to 2029 period:

1) Six bus-tie reactors to alleviate short circuit capacity constraints at stations that cannot be relieved through station expansion work or by increasing station equipment thresholds. Table 3 below identifies the station buses where bus tie reactors are proposed.

Table 3: Locations of Proposed Bus Tie Reactors (2025-2029)

Station Name	Bus	2023 Available Short Circuit Capacity (MVA)	2029 Available Short Circuit Capacity (MVA)
Cecil	CE-A1A2	59.7	-32.7
Esplanade	X-A1A2	58.9	-7.6
Leslie	51-BY	3.2	-46.6
Richview	88-BY	-40.3	-41.2
Runnymede	11-JQ	113.6	-103.3
Woodbridge	D6-BY	-27.3	-28.0

2) Real-time monitoring and control systems must be installed at every site to monitor for islanding and thermal conditions.[13] In accordance with the Distribution System Code, monitoring and control systems for renewables are paid for by the distributor rather than the customer as is the case for non-renewables.
3) Toronto Hydro plans to deploy nine energy storage systems, with an aggregate capacity of 10.2 MW, to enable the connection of forecasted renewable growth on the nine high-priority feeders outlined in Table 3 above. The utility selected these feeders based on their existing high renewable DER penetration, low MLGR ratio and high forecasted renewable DER growth. Please refer to the Non-Wires Solutions program for more information about the feeder selection process and analysis (Exhibit 2B, Section E7.2).
4) Toronto Hydro plans to install a new bus at Sheppard TS which will introduce an estimated 126 MVA of new short circuit capacity at the station to enable new DER growth. The utility selected this option due to the technical limitations of installing a bus-tie reactor on the Gas Insulated Switchgear (GIS) bus at Sheppard TS.[14] /C

[13] Exhibit 2B, Section E5 – Generation Protection and Control, section E5.5.4.2.
[14] Please refer to the Stations Expansion program in Exhibit 2B, Section E7.4 for more details. /C

Table 4 below provides the short circuit capacity constraints forecasted at this station.

Table 4: Current and Forecasted Short Circuit Capacity at Sheppard TS

Station Name	Bus	2023 Available Short Circuit Capacity (MVA)	2029 Available Short Circuit Capacity (MVA)
Sheppard	47-EZ	-57.3	-91.4

/C

/C

E4 Capital Expenditure Summary

This section provides an overview of Toronto Hydro's capital and system maintenance and operational (O&M) expenditures for the 2020-2029 rate period, including explanations of: (i) variances in forecast expenditures from the 2020-2024 capital plan versus actual expenditures during over the 2020-2024 rate period, and (ii) shifts in 2025-2029 forecast expenditures versus 2020-2024 historical expenditures by investment category.

The explanations provided in this section are complimentary to the information presented in OEB Appendices 2-AB,[1] and 2-AA which are appended to this section.[2] Detailed explanations for material variances and trends are also provided within the 'Expenditure Plan' section of each capital program in sections E5 to E8.

Toronto Hydro confirms that there are no expenditures for non-distribution activities included in this application.

<u>Accounting Treatment for CWIP</u>

Expenditures for capital projects that span more than one calendar years are recorded in a Construction Work-in Progress ("CWIP") account until the project work is completed. Given the nature of its capital expenditure programs and projects, at any point in time, Toronto Hydro has a balance in the CWIP account. Initial capital expenditures are recorded in CWIP until the project is complete, and capitalized. Under Modified International Financial Reporting Standards ("MIFRS"), a financing charge, referred to as Allowance for Funds Used During Construction ("AFUDC"), is added to capital projects that exceed six months to complete. AFUDC is part of Other Capital Expenditures as further explained below.

<u>Other Capital Expenditures</u>

Toronto Hydro's capital expenditures under the Other Capital Expenditures category includes Allowances for Funds Used During Construction ("AFUDC") and miscellaneous capital, as described in OEB Appendices 2-AB.[3]

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[1] Exhibit 2B, E4, Appendix A
[2] Exhibit 2B, E4, Appendix B
[3] *Supra* note 1.

- AFUDC is capitalized in accordance with the OEB's Accounting Procedures Handbook, Article 410. The AFUDC rate applied by Toronto Hydro under MIFRS for 2020 to 2022 actuals, 2023 to 2024 bridge, and 2025 to 2029 forecast years is based on Toronto Hydro Corporation's weighted average cost of borrowing.
- Miscellaneous capital primarily consists of pre-capitalized inventory and major tools. The value of pre-capitalized inventory results from the change in capitalized inventory levels between years.[4] The utility purchases major tools in the normal course of operations and on an ongoing basis to replace worn or broken tools, as required, and to install, commission and otherwise complete capital activities.

E4.1 Plan versus Actual Variances for 2020-2024

In Toronto Hydro's 2020-2024 rate application, the OEB approved a custom incentive rate-setting mechanism on the basis of a capital expenditure plan of $2,710.7 million.[5]

Due to the imposition of a 0.9% stretch-factor on Toronto Hydro's capital related revenue requirement, along with other drivers such as extraordinary inflation and increases in customer connections and load demand needs, the utility had to manage its 2020-2024 capital plan with a constrained level of funding relative to the needs and the costs of the plan. To do so, the utility reprioritized projects and adjusted program pacing as needed. Where possible, Toronto Hydro balanced the execution of the plan to deliver on high-priority objectives, and manage performance across numerous outcomes. Key objectives and outcomes included:

- Removing assets containing or at risk of containing PCB from the system by 2025 to comply with environmental obligations;
- Removing box construction framed poles from the system by 2026 to advance public and employee safety outcomes;
- Ensuring that the grid has sufficient capacity to serve areas of high-growth and development in the city and to connect customers in a timely and efficient manner;
- Installing monitoring and control equipment in areas like the network system to increase system observability and drive operational productivity.

[4] Ontario Energy Board, *Accounting Procedures Handbook for Electricity Distributors*, (January 1, 2012), Article 410.
[5] EB-2018-0165, Draft Rate Order (Filed: January 21, 2020; Updated: February 23, 2020), Schedule 4 – Capital Expenditures.

- Replacing assets at a pace sufficient to maintain reliability with historical levels of performance and to maintain system health in line with 2017 condition.
- Staying on track to complete Copeland TS – Phase 2 project and the Control Operations Reinforcement program on time within budget.

As described in Section D1, Toronto Hydro goes through an extensive annual business planning process to strike a balance across these objectives. To ensure the utility was able to meet specific needs of the system (including those listed above) and manage within the operating conditions of the current period (including 40-year high inflation), Toronto Hydro had to reduce the pacing of certain system renewal investments: [6]

- the replacement of direct-buried cables as part of its Underground System Renewal – Horseshoe program;[7] and
- the replacement of wood poles in its Overhead System Renewal program.[8]

Reduction in these programs placed additional pressure on reliability performance. Toronto Hydro had to carefully manage these pressures to honour its commitment to maintain reliability performance over this period and meet other key plan objectives noted above. The utility succeeded in this balancing act as it:

- maintained reliability performance relatively consistent over its historical average. The utility's SAIDI performance improved over the last five years (2018-2022), averaging 0.85 hours and exceeding the OEB's distributor target of 0.87 hours. The utility's SAIFI performance is slightly worse than the OEB's distributor target of 1.20, averaging at 1.30 during 2018 to 202, but comparable to the 2013-2022 average of 1.28;
- Connected approximately 10,000 customers through the Customer Connections program, with an increase of $147.5 million (71 percent) in capital expenditures over the forecast to maintain and exceed performance;

[6] As described in detail in Exhibit 1B, Tab 3, Schedule 3, these include COVID-19, extraordinary inflation, and workforce challenges.
[7] Exhibit 2B, Section E6.4.
[8] Exhibit 2B, Section E6.6.

- Continued to support expansion and relocation projects as part of the Externally Initiated Plant Relocations and Expansion program including but not limited to the Metrolinx GO expansion project and the TTC initiated Easier Access Program;
- Reduced constraints on the system through the Load Demand program by alleviating 131 MVA on highly loaded buses, reducing the number of highly loaded feeders by 10, improving the civil infrastructure associated with station expansion of five Terminal Stations as well as civil rebuild at the distribution level, and maintaining the number of feeders subject to switching restrictions during the summer months to under 10;
- Replaced approximately 50,000 residential, small commercial, and industrial meters as part of the AMI 2.0 project in the Metering program over the rate period which improves billing accuracy, faster outage response, improved network range, enhanced cyber security protection, increased grid transparency, data granularity and analytical capabilities;[9]
- Completed installations of radio communication link equipment required to facilitate the two-way communication flow between DER facilities and the Toronto Hydro Control Centre at more than 100 sites during the period of 2020 to 2023;
- Replaced 444 box-framed poles with an additional 236 anticipated over the rate period, enabling the utility to meet its commitment to remove box construction poles from the system by 2026;
- Converted 384 customers from aging rear lot service to safer and more reliable front lot underground during 2020 to 2022, and is on track to convert approximately 299 rear lot customers during 2023 to 2024;
- Addressed approximately 3,500 transformers containing or at risk of containing PCBs with upward pressure on the cost of materials attributed to supply chain issues from the COVID-19 pandemic through a combination of inspection and replacement over the course of 2020-2022;
- Addressed aging and failure risk prone direct-buried cable in the underground system through replacement of 79 kilometers of direct-buried cable over 2020-2023 for an estimated total of 105 kilometers by the end of the rate period;

[9] Exhibit 2B, Section E5.4.

- Continued to address obsolete PILC and AILC cable through the Underground Renewal – Downtown program by replacing an estimated 30 circuit-km of PILC cable and 9 circuit-km of AILC over the 2020-2024 rate period;[10]
- Addressed deteriorated and non-submersible units through the investments in the Network System Renewal program by replacing 82 network units and an additional 95 network units by the end of the rate period;[11]
- Improved flexibility of the system through investments in the System Enhancements program that includes the addition of tie points, sectionalizing points and upgrades to undersized loops, and installation of switchgear ties between Copeland and Windsor stations;[12]
- Continued to advance capabilities and build upon progress from the previous rate period through Local Demand Response initiatives outlined in the Non-Wires Solutions program (E7.2) by targeting Manby TS and Horner TS over the 2020-2024 period;
- Commissioned 379 vaults with an additional 320 over the rate period to modernize just under 90 percent of the secondary network through the Network Condition Monitoring and Control ("NCMC") program,[13] achieving sustained operating expenditure savings and improved network resiliency; and gaining crucial organization grid modernization experience that will be applied to the 2025-2029 rate period;
- Increase the capacity of Copeland Station with a Phase 2 expansion that provides an addition 144MVA to support the growth and development of Central Waterfront area and enhance reliability and resiliency in the downtown core. This project is on time and below budget by approximately $5 million.[14]
- Improving operational resilience and strengthening system security by completing construction of a dual Control Centre by the end of 2023; and
- Improving cyber security and business efficiency and laying the foundation for future customer experience enhancements by upgrading the Customer Information System ("CIS") to a modern, vendor-supported version by Q2 of 2024.

[10] Exhibit 2B, Section E6.3.
[11] *Supra* note 8.
[12] Exhibit 2B, Section E7.1.
[13] Exhibit 2B, Section E7.3.
[14] Copeland Phase 2 savings are derived from continuous improvement in execution based on the utility's experience and lessons learned from Copeland Phase 1. For example, more cost-effective procurement agreements for major equipment.

Toronto Hydro forecasts $2,787.4 million in net capital expenditures over the completion of the 2020-2024 rate period, which is three percent higher than the $2,710.7 million approved by the OEB in the 2020-2024 DSP.

In Table 2 below, Appendix 2-AB, and throughout the remainder of this section, Toronto Hydro refers to the OEB Approved values for 2020-2024 as the "Plan" for 2020-2024. By comparing the 2020-2024 plan to the actual and forecasted bridge year expenditures, the utility is able to provide a complete picture of the management and execution of the current plan.

Table 2 below provides a breakdown of the Plan and of actual plus bridge expenditures by year and by category, and the subsections that follow the table provide explanations for each category:

Table 2: 2020-2024 Capital Expenditure Summary ($ Millions)

OEB Category	Historical									Bridge					
	2020			2021			2022			2023			2024		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	For.	Var.	Plan	For.	Var.
System Access	164.9	225.2	37%	193.0	240.7	25%	184.7	244.3	32%	197.4	260.5	32%	211.1	289.6	37%
System Renewal	290.5	261.7	(10%)	307.2	247.3	(19%)	304.7	276.6	(9%)	319.4	314.0	(2%)	309.5	358.8	16%
System Service	34.6	33.4	(3%)	60.1	68.0	13%	71.3	67.1	(6%)	33.6	32.8	(2%)	38.5	24.3	(37%)
General Plant	78.8	56.1	(29%)	92.8	72.4	(22%)	88.1	112.9	28%	76.8	96.5	26%	84.4	80.7	(4%)
Other	5.3	17.5	232%	6.5	4.8	(26%)	8.9	12.8	44%	6.3	12.6	100%	5.7	7.7	35%
Total CAPEX	**574.1**	**593.9**	**3%**	**659.6**	**633.3**	**(4%)**	**657.7**	**713.7**	**9%**	**633.5**	**716.4**	**13%**	**649.3**	**761.2**	**17%**
Capital Contributions	(74.8)	(145.8)	95%	(102.7)	(100.1)	(2%)	(93.9)	(115.8)	23%	(94.5)	(133.4)	41%	(97.6)	(135.9)	39%
Net CAPEX	**499.2**	**448.1**	**(10%)**	**556.9**	**533.2**	**(4%)**	**563.8**	**597.9**	**6%**	**539.1**	**582.9**	**8%**	**551.7**	**625.3**	**13%**
System O&M	126.3	117.1	(7%)	-	117.5	-	-	124.1	-	-	127.1	-	-	135.0	-

Note: Capital contributions include contributions made by customers and third-parties.

E4.1.1 System Access 2020-2024 Variance Analysis

From 2020 to 2024, System Access expenditures are forecasted to be approximately 33 percent higher than planned due to the following factors:

- Expenditures in the Customer Connections program are forecasted to be approximately 55 percent higher than the plan on a gross basis and 71 percent higher on a net basis.[15] This program is highly volatile and driven by various external factors (e.g. size and location of connections, available capacity provisions, economic drivers). Toronto Hydro experienced a higher than anticipated increase in system access requests for large projects (greater than 5MVA demand) over this period. The increases in 2021-2022 were attributed to the unforeseen emergence of large connections across a broad spectrum of market segments including: multi-use projects (commercial-condominium), institutional infrastructure, industrial infrastructure, data centres, and transit projects (Finch West LRT). Toronto Hydro factored in these trends in developing its 2025-2029 forecasts. See the Customer Connections program for additional details.
- Expenditures in the Load Demand program are forecasted to be approximately 38 percent higher than planned.[16] This variance was driven by the need for load transfers between stations and feeders to alleviate system constraints. Like Customer Connections, the Load Demand program can vary significantly from one year to the next due to expected new connections, voltage conversions, and an updated station load forecast. To keep up with these drivers, the Load Demand program forecast is re-evaluated annually.
- Expenditures in the Externally Initiated Plant Relocations and Expansions program are forecasted to be approximately 18 percent higher than planned due to an increase in the volume and complexity of third-party relocation and expansion projects.[17]
- Expenditures in the Metering Program are forecasted to be 34 percent lower than planned. Due to procurement delays and funding constraints, Toronto Hydro adjusted the pacing of meter replacements in the current rate period.[18]

E4.1.2 2020-2024 Variances: System Renewal

From 2020 to 2024, System Renewal expenditures are forecasted to be approximately 5 percent lower than planned due to the following factors:

[15] Exhibit 2B, Section E5.1.
[16] Exhibit 2B, Section E5.3.
[17] Exhibit 2B, Section E5.2.
[18] *Supra* note 9.

- Expenditures in the Area Conversions program are forecasted to be approximately 24 percent higher than planned.[19] The net increase in the program is driven by the Box Construction Conversion segment, which saw higher spending due to required shifts in project scheduling as well as incremental cost pressures related to the complexity of the work and various external cost drivers (e.g. coordination with the CafeTO program). For more details, please refer to section E6.1.4.2. The Rear Lot Conversion investments also saw a slight increase of approximately 4 percent.
- Expenditures in the Underground System Renewal – Horseshoe,[20] and Underground System Renewal – Downtown are forecasted to be approximately 24 percent lower than planned.[21] Through its planning and execution process, Toronto Hydro determined that it was necessary to constrain investment in these programs in order to manage funding pressures and balance the attainment of multiple objectives within the plan. The utility temporarily shifted its execution strategy to a target spot replacement approach focused on PCB removals, which meant taking on incremental risk in its aging cable population. That accumulation asset failure risk is driving the need for incremental investment in key underground assets such as cables in 2025-2029. In Downtown program, Toronto Hydro was able to find some savings over the 2020-2024 rate period by engineering an alternative approach to cable renewal work which leverages existing available civil infrastructure to the extent possible.
- Expenditures in the Overhead System Renewal program are forecasted to be approximately 18 percent lower than planned due to the same considerations,[22] as discussed above for the Underground Renewal program. Toronto Hydro managed a reduced pace in this program by temporarily shifting its execution strategy to a spot replacement approach focused on PCB removals, and deferring larger area rebuilds to address deteriorating poles and switches as well as obsolete 4 kV feeders.
- Expenditures in the Network System Renewal program are forecasted to be approximately 26 percent higher than planned.[23] The increase is driven in large part by design and execution complexities that emerged as the projects matured from conceptual to detailed design. This includes additional scope of work (e.g. civil construction and legacy cable removal), material

[19] Exhibit 2B, Section E6.1.
[20] Exhibit 2B, Section E6.2.
[21] *Supra* note 10.
[22] Exhibit 2B, Section E6.5.
[23] *Supra* note 7.

cost increases driven by supply chain disruptions, and work execution challenges related to field conditions (e.g. urban congestion) and operational complexities (e.g. coordination challenges).

- Expenditures in the Stations Renewal program are forecasted to be approximately 23 percent higher than planned due to project complexity, necessary scope increases, and inflationary cost escalations.[24]

E4.1.3 2020-2024 Variances: System Service

From 2020 to 2024, System Service expenditures are forecasted to be approximately five percent lower than planned due to the following factors:

- Expenditures in System Enhancements program are forecasted to be approximately 5 percent lower than planned.[25] Toronto Hydro constrained the pace of investment in this area by deferring work to the 2025-2029 rate period and by leveraging opportunities to carry out some of the planned enhancement work within related renewal programs.
- Expenditures in the Energy Storage Systems (ESS) segment, which has been re-mapped to the Non-Wires Solutions program, are forecast to be 79 percent lower than planned due to challenges in finding a cost-effective site for an ESS installation, as well as supply chain constraints. Faced with these challenges, and further studying the use cases and the regulatory considerations of ESS as a grid-asset Toronto Hydro decided to evolve its ESS investment strategy to focus on enablement of renewables electricity generation resources.[26]

Phase 2 of Copeland TS is expected to be completed in early 2024, therefore, there are no expansion costs forecast for the 2025-2029 rate period. 2020-2024 expenditures are forecast to be about 1 percent higher than planned. For further details, please refer to Stations Expansion program.[27]

[24] *Supra* note 8.
[25] *Supra* note 12.
[26] Exhibit 2B, Section E7.2.
[27] Exhibit 2B, Section E7.4.

E4.1.4 2020-2024 Variances: General Plant

From 2020-2024, General Plant expenditures are forecasted to be aligned with the Plan, as a result of variances in the following programs offsetting each other:

- Expenditures in the Facilities Management and Security program are forecasted to be 41 percent higher than planned due to need for additional unplanned reactive asset replacements, such as the replacement of a failed HVAC unit at the 14 Carlton work centre, the installation of hatchway railings and safety devices, and physical security enhancements in response to security incidents; incremental work to reduce building emissions;, and overall higher costs of materials and labour driven by supply chain disruptions and inflationary pressures in the construction industry.[28]
- Expenditures in the IT/OT program are forecasted to be 8 percent lower than planned. Increases in cybersecurity investments required to reinforce system protection due to an increase in external threats were offset by savings resulting from the prudent decision to defer the Enterprise Resource Planning ("ERP") system upgrade. Toronto Hydro made this decision when it learned that the system vendor, SAP, extended maintenance support for the existing ERP platform until 2027, and extended support until 2030.[29]

The Control Operations Reinforcement Program included in the 2020-2024 Plan is expected to be complete before 2025-2029 on time and within budget.[30]

E4.1.5 2020-2024 Variances: Other Capital

Expenditures in the "Other Capital" investment category are projected to be 69 percent higher than forecast over the 2020-2024 rate period. The primary driver for this increase is a result of a strategic decisions to increase pre-capitalized inventory to mitigate plan execution risks driven by supply chain disruptions (i.e. extended lead times and delivery uncertainty) experienced during the COVID-19 pandemic. This decision enabled Toronto Hydro to ensure equipment availability for its growing capital program, including critical compliance investments in at-risk PCB transformer replacements.[31]

[28] Exhibit 2B, Section E8.2.
[29] Exhibit 2B, Section E8.4.
[30] EB-2018-0165, Exhibit 2B, Section E8.1.
[31] Please refer to Exhibit 4, Tab 2, Schedule 13 for further details on supply chain challenges

E4.1.6 2020-2024 Variances: System O&M

System Operations and Maintenance ("System O&M") expenditures are driven by the need to maintain distribution assets and support the execution of Toronto Hydro's capital, maintenance, system response, and customer-driven work activities. The expenditures include the following activities:

- Preventative and Predictive Maintenance Programs (Exhibit 4, Tab 2, Schedule 1-3);
- Corrective Maintenance (Exhibit 4, Tab 2, Schedule 4)
- Emergency Response (Exhibit 4, Tab 2, Schedule 5);
- Disaster Preparedness Management (Exhibit 4, Tab 2, Schedule 6);
- Control Centre Operations (Exhibit 4, Tab 2, Schedule 7);
- Customer Operations (Exhibit 4, Tab 2, Schedule 8);
- Asset and Program Management (Exhibit 4, Tab 2, Schedule 9);
- Work Program Execution (Exhibit 4, Tab 2, Schedule 10); and
- Supply Chain (Exhibit 4, Tab 2, Schedule 13);

System O&M expenditures are forecast to increase from approximately $117.1 million in 2020 to $135 million in 2024, representing an average annual increase of 4 percent over the period. The primary drivers are asset and system maintenance needs, compliance obligations and resource requirements to support a higher volume and greater complexity of work in Toronto Hydro's service territory as the city of Toronto continues to grow, digitize, and decarbonize its economy. Below is a more detailed list of specific drivers:

- Corrective maintenance to address safety, reliability and environmental risks arising from a higher number of deficiencies identified through inspection programs.
- Compliance with incremental requirements imposed by the Electrical Safety Authority with respect to grounded-wye customer supply points and grounding of unused primary lines.
- The introduction of a Cable Diagnostic Testing program to support a more targeted approach for managing short-term cable systems risks.
- An increase to the Vegetation Management program to mitigate the reliability impacts of Toronto's expanding tree canopy.
- Increased overhead switch maintenance volumes and costs to ensure optimal maintenance cycles and keep pace with a growing population of assets.

- Greater requirements for testing, resealing, and reusing meters.
- The introduction of incremental Storm Guying inspections and corrective action to improve resiliency of poles during high wind events.
- The introduction of inspections for communication infrastructure at DER sites.
- Workforce requirements to support higher volumes and complexity of work, prepare the grid for energy transition and build capabilities required to support grid modernization objectives, including improvements to data quality and additional analytical capacity.
- An increase due to external factors such as weather in Emergency Response and customer demand for services such as vault access, locates and connections in Customer Operations.

The volume of maintenance for an asset class is dictated by asset class maintenance cycles and can vary from year-to-year. Similarly, the extent of maintenance required for inspected assets can vary from year-to-year depending on observed condition and other factors. To manage natural variances and volatility in maintenance programs, Toronto Hydro paces the execution of its maintenance plans where feasible and appropriate. For example, an increase in station battery failure for a particular year may be offset by a deferral of checker plate replacements at submersible vault locations or vault cleaning activities in Network Vaults.

E4.1.6.1 Capital Investment and System O&M

While capital investments can impact System O&M costs in different ways as discussed below, identifying specific impacts for each year is not practical due to the numerous factors involved and the gradual and ongoing nature of many of these impacts. Instead, the following summarizes and provides examples of the various ways System O&M costs are impacted by capital investments.

As discussed in more detail in Section D3.1.1.3, a significant portion of maintenance program costs are for activities which are independent of capital investments, such as cyclical inspections to meet minimum requirements under the Distribution System Code, and, where there is an impact of capital investments, the directional relationship depends on a number of factors, including the type of capital investment. For example, Growth investments are generally expected to put upward pressure on maintenance requirements as the number of assets on the distribution system increases. In addition, Toronto Hydro may introduce new assets, which require the introduction (and over time expansion) of new maintenance and inspection activities. For example, in 2022 Toronto Hydro began annual inspections, testing, and cleaning of its Bulwer Battery Energy Storage System ("BESS") assets under the Preventative and Predictive Station Maintenance program and expects to expand this to additional Toronto Hydro-owned energy storage systems as they are added under the Non-Wires Solutions capital program. [32,33] While Modernization investments can similarly increase maintenance costs by installing new assets such as SCADA-mate switches, it can also help to reduce some O&M costs. For example, the NCMC program installs sensors in network vaults providing remote monitoring and control, and through this Toronto Hydro expects to reduce the number of planned vault inspections required for each network vault per year, reducing maintenance costs by approximately $275,000 each year in the Preventative and Predictive Underground Line Maintenance program once all vaults are commissioned. [34] While this benefit of the NCMC program is not expected to be realized until 2027, the utility has already avoided costs by reducing the need for crews to visit vaults during outage events or to identify and investigate deficiencies.[35]

For Sustainment investments, typical like-for-like asset replacement is generally expected to have minimal to no impact on maintenance spending. If replacements are done at a high enough pace to materially improve asset health demographics (which is generally not the goal), this could in turn reduce the expected volume of deficiencies requiring corrective intervention (e.g. repair). However, this is complicated by the fact that a younger and healthier asset base may require relatively higher levels of Corrective Maintenance for subsets of assets due to the fact that younger equipment with defects may be better suited to repair (i.e. maintenance) as opposed to full replacement (i.e. reactive capital). Toronto Hydro does anticipate that Sustainment programs targeting legacy assets such as air-blast circuit breakers and the 4.16 kV system (including box construction and rear lot) will contribute to a gradual and modest reduction in costs related to legacy equipment maintenance as the population declines and the assets are replaced with equipment that typically requires lower maintenance costs (including emergency or corrective maintenance) or is maintenance free. For example, air-blast circuit breakers rely on air compressors, which Toronto Hydro inspects and maintains twice a year. As Toronto Hydro removes air-blast circuit breakers from the system through

[32] Exhibit 4, Tab 2, Schedule 3.
[33] *Supra* note 26.
[34] Exhibit 4, Tab 2, Schedule 2.
[35] For example, as of June 2023 Toronto Hydro had saved approximately $120,000 by not deploying crews during outage events. See Exhibit 2B, Section E7.3 for more details on the NCMC program and its benefits.

its Stations Renewal program, it will reduce and eventually eliminate the volume of these inspections under the Preventative and Predictive Station Maintenance program.[36]

As discussed in more detail in Section E4.2.6 below, growth in the overall size of the capital investment program is expected to increase costs in O&M programs that support such investments, including Asset and Program Management,[37] and Supply Chain.[38]

E4.1.7 2020-2024 Construction Work in Progress ("CWIP")

Table 3 below provides the 2020-2024 CWIP. Detailed explanations for capital expenditures are provided above and explanations for trends in In-Service additions are provided in Exhibit 2A, Tab 1, Schedule 1.

Table 3: Historical (2020-2022) and Bridge (2023-2024) CWIP ($ Millions)

	Actual			Bridge	
	2020	**2021**	**2022**	**2023**	**2024**
Opening CWIP	381.2	380.6	427.8	471.2	442.4
Additions (CAPEX)	447.4	532.4	597.8	579.1	620.3
Deductions (In Service Additions)	(447.9)	(485.2)	(554.4)	(607.9)	(606.3)
Closing CWIP	380.6	427.8	471.2	442.4	456.4

Note: Variances due to rounding may exist

[36] Exhibit 2B, Section E6.6 and Exhibit 4, Tab 2, Schedule 3.
[37] Exhibit 4, Tab 2, Schedule 9.
[38] Exhibit 4, Tab 2, Schedule 13.

E4.2 Forecast (2025-2029) vs. Historical (2020-2024) Expenditures

Table 4 below shows the contribution to the total capital program of each investment category for the current and future rate period. Compared to the current 2020-2024 rate period, there is a shift in the 2025-2029 rate period towards System Access and System Service investments to:

- keep pace with the demands of customers in a city that is growing, digitizing and decarbonizing its economy, and
- prepare the grid for the energy transition that is set to unfold over the next two decades by modernizing the utility's infrastructure and operations to improve resiliency, enable DER integration and deliver long-term reliability and efficiency benefits to customers.

Table 4: Historical and Forecast Share of Total by Investment Category

Category	Historical Share of Total (%)						Forecast Share of Total (%)					
	2020	2021	2022	2023	2024	Avg.	2025	2026	2027	2028	2029	Avg.
System Access	18%	26%	21%	22%	25%	**22%**	30%	30%	28%	24%	23%	**27%**
System Renewal	58%	46%	46%	54%	58%	**53%**	49%	48%	48%	51%	53%	**50%**
System Service	7%	13%	11%	6%	4%	**8%**	5%	5%	8%	9%	10%	**8%**
General Plant	13%	14%	19%	17%	13%	**15%**	14%	16%	15%	14%	12%	**14%**
Other CAPEX	4%	1%	2%	2%	1%	**2%**	1%	1%	1%	1%	1%	**1%**
Total	100%	100%	100%	100%	100%	**100%**	100%	100%	100%	100%	100%	**100%**

/C

In the sections that follow, Toronto Hydro provides a summary of key programs and investment priorities that are driving the planned increases in each of these categories in 2025-2029 compared to 2020-2024. Additional details about each of these programs and priorities are found throughout other section of this Distribution System Plan.

E4.2.1 System Access: Historical vs. Forecast Expenditures

Table 5: System Access: 2020-2029 Expenditures ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Access	80.4	140.3	128.4	127.1	153.7	220.1	229.1	224.0	196.6	182.7

/C

Toronto Hydro expects System Access expenditures to continue to increase into the 2025-2029 rate period. As discussed in Section E2.2, this overall increase is driven by two primary considerations:

- continued growth and development in the city of Toronto, including the expected impacts of electrification as more customers turn to electricity for their day to day needs such as transportation and building heating systems;
- necessary replacement of end-of-life revenue meters which will also offer Toronto Hydro the opportunity to modernize this critical part of the system with Advanced Metering Infrastructure (AMI) 2.0.

As discussed in Section D2, the City of Toronto leads North America in new buildings under construction. Toronto Hydro expects continued growth in customer load and generation connections, as well as major infrastructure projects (e.g. transit development) that are externally initiated. Toronto Hydro is also due to renew its sizable population of end-of-life residential and small commercial and industrial (C&I) revenue meters.[39] Inflation for materials, labour and other construction-related costs is also driving increases in certain programs. For more information on the programs in this category, refer to Section E5.

E4.2.2 System Renewal: Historical vs. Forecast Expenditures

Table 6: System Renewal Expenditures: 2020-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
System Renewal	261.5	247.3	276.5	314.0	358.8	359.7	366.5	391.3	423.7	429.1

Over the 2025-2029 rate period, Toronto Hydro plans to increase its System Renewal investments in the 2025-2029 rate period by approximately 35 percent compared to 2020-2024 rate period. As discussed in Section E2.2, this increase is necessary to manage significant safety, reliability, and environmental asset risks, maintain the system in a state of good repair by managing the overall health demographics of assets, and ensure stable and predictable grid performance for current and future customers.

[39] *Supra* note 9.

As mentioned in Section E4.1.2 above, Toronto Hydro constrained investment in key System Renewal programs to manage funding pressures in the 2020-2024 rate period. This prudent decision, along with other factors, led to increasing investment needs in the 2025-2029 rate period including:[40]

- asset condition demographics (e.g. wood pole condition);
- persistent backlogs of high-risk legacy assets such as direct-buried cable;
- growing asset stewardship risks in the downtown core, including those related to aging lead cable and deteriorating civil assets;
- growing backlog of critical stations-level equipment at risk of failure;
- increasing performance pressures on the system from climate change, necessitating greater investment in resiliency;
- elimination of PCB at-risk assets from the distribution system;
- the increasingly urgent need to convert aging, legacy 4 kV / 13.8 kV parts of the system to higher voltage standards that are capable of handling electrified loads, DERs and automation;
- the need to accelerate replacement of obsolete mechanical stations relays with digital relays capable of supporting advanced operational functions and grid automation; and
- anticipated cost pressures from construction inflation in the City of Toronto which reached a 40-year all time high in the 2020-2024 rate period.

Toronto Hydro expects to eliminate PCB at-risk units from the distribution system by 2025 and box-framed poles by 2026. The winddown of these investment priorities will enable the utility to ramp-up investment in the conversion of legacy 4 kV / 13.8 kV parts of the system. In addition to addressing the reliability risks posed by these aging assets, the conversion of these configurations to higher voltage standard enables the utility to accommodate higher volumes of electrified loads.

E4.2.3 System Service: Historical vs. Forecast Expenditures

Table 7: System Service Expenditures: 2020-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Service	32.8	68.4	67.2	32.8	24.3	38.3	35.0	66.0	78.1	84.3

/C

[40] See Sections D1, E2, and Section E6 for additional details.

Over the 2025-2029 rate period, Toronto Hydro plans to increase its System Service investments by approximately 34 percent compared to 2020-2024 investment levels. Expenditures in this category are central to Toronto Hydro's strategy to expand and modernize its grid and operational capabilities to address key drivers of change within its business, including electrification, DER proliferation, and climate change impacts. For more information about this strategy see Section D4 – Capacity Planning and Electrification Strategy and D5 – Grid Modernization Strategy.

Increased investments in this category are largely driven by:

- capacity expansion needs in the Stations Expansion program including investment in a new Transformer Station to support expected load growth in the Downsview areas and Hydro One contribution to expand capacity at existing stations, such as Sheppard TS.[41]
- a paced ramp-up in the System Enhancement program to enhance system observability and controllability, and enable the utility to be ready for widescale grid automation in the horseshoe areas of its system in the next decade.[42] These investments are expected to deliver long-term reliability and efficiency benefits to customers.
- investments in Energy Storage systems (ESS) to improve the grid's capacity to connect and integrate Renewable Energy Generation (REG) connections which are expected to play an increasing role in advancing customers' and stakeholders decarbonization objectives.

E4.2.4 General Plant: Historical vs. Forecast Expenditures

Table 8: General Plant Expenditures: 2025-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
General Plant	56.1	72.4	112.9	96.5	80.7	103.9	119.1	124.9	116.1	98.6

Over the 2025-2029 rate period, Toronto Hydro plans to increase its General Plant investments by approximately 34 percent compared to 2020-2024. Expenditures in this category are driven by asset lifecycle management for fleet, facilities, and IT equipment that support the efficient execution and management of Toronto Hydro's capital and operational work programs. In addition, Toronto Hydro plans to continue to invest in paced decarbonization of its facilities and fleet emissions, as well as in

[41] *Supra* note 27.
[42] *Supra* note 12.

the relocation of an enterprise data centre. The latter project is required to enable the utility to expand and reliably operate this critical piece of infrastructure in accordance with the growth of the distribution system, as the significant challenges associated with the data centre's current location preclude such expansion and pose significant business continuity and reliability risks.

This category is also driven by investments in cyber security and enterprise technology software solutions, which are needed to achieve the following outcomes:

- strengthen protection and resilience against increasing digital threats brought on by advancements in technology and changes in geopolitical dynamics;
- support grid modernization efforts detailed in Section D5;
- drive continuous improvement in productivity through process automation;
- leverage technology tools and capabilities to serve customers in a timely and effective manner and deliver good experience as more customers turn to electricity for their day-to day energy need; and
- implement public policy initiatives and maintain compliance with legislative and regulatory requirements.

E4.2.5 Other Capital: Historical vs. Forecast Expenditures

Table 9: Other Capital Expenditures: 2025-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Other Capital	17.4	4.6	12.8	12.6	7.7	6.2	7.0	8.3	9.2	10.2

Other Capital includes forecasted amounts for Allowance for Funds Used during Construction ("AFUDC") which are required during the execution of capital programs in the 2025-2029 rate period.[43]

[43] As discussed in Section E4.1.5, Road Cut Restoration costs and Major Tools are attributed directly to capital program expenditures and are not included in Table 7.

E4.2.6 System O&M: Historical vs. Forecast Expenditures

Table 10: System O&M Expenditures: 2020-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System O&M	117.1	117.5	124.1	127.1	135.0	144.1	148.9	153.0	159.0	164.5

System O&M expenditures are expected to increase at an average annual rate of approximately 3 percent between 2025 and 2029. The increases are driven by a number of factors:

- Toronto Hydro is expanding inspection and maintenance activities in key areas through the Preventative and Predictive maintenance programs, resulting in an 11 percent increase between 2024 and 2025, followed by a moderate 1 percent average annual increase from 2026-2029. Starting in 2025 Toronto Hydro is adjusting inspection cycles for wood poles from ten years to eight years to manage failure risk driven by wood pole age and condition demographics. Toronto Hydro will also begin inspecting concrete and steel poles as part of its Pole inspection program on a ten-year cycle. Toronto Hydro will transition to a minimum six-year maintenance cycle for overhead switches, which represents an increase from the current variable cycle, which is generally greater than six years. Toronto Hydro will continue to ramp up the Cable Diagnostic testing segment in Preventative and Predictive Underground Line Maintenance program, collecting key condition information on a greater number of feeders to inform both short- and long-term investment decisions. The introduction of incremental inspection activities at DER sites and increasing volume of Energy Storage locations within the Preventative and Predictive Stations program also drive cost increases. Toronto Hydro plans to reduce its Network Vault civil inspection program starting in 2027 as a result of the implementation of Network Condition Monitoring and Control resulting in reduced costs in that program. The large majority of Toronto Hydro's inspection and maintenance programs are cyclical in nature, with cycles established to meet regulatory requirements, as discussed in Exhibit 2B, Section D3. As a result, significant reductions to inspection or maintenance programs are not expected in the 2025-2029 period. Differing volumes of work and inflationary impacts will result in year over year fluctuations in expenditures between 2025-2029 within these programs;[44]

[44] Exhibit 4, Tab 2, Schedules 1-3.

- The Corrective Maintenance program expenditures increase by 14 percent between 2024 and 2025, followed by a 3 percent average annual increase from 2026-2029. The increase in the Corrective Maintenance Program is driven by the need to address a growing backlog of P3 deficiencies within the system. Expected expenditures related to increasing spot tree trimming and corrective work for DER sites also drive an increase in this program. For more details, please see Exhibit 4, Tab 2, Schedule 4;
- A 12 percent increase between 2024 and 2025 is forecasted within the Emergency Response program. Inflationary pressures including increased labour and vehicle costs for services and a new contract for external resources that will be effective in 2025 contribute to the increase. From 2026-2029, expenditures align to a 2 percent average annual increase;[45]
- The Supply Chain program is growing by 14 percent between 2024 and 2025 followed by an average annual increase of 6 percent between 2026-2029. The increase in costs is primarily due to higher payroll and contract costs required to support an expanded Capital Program within a more complex global supply chain environment;[46]
- The Asset and Program Management program will have an average annual increase of 6 percent over the 2025-2029 rate period driven primarily by higher payroll and external contract costs to support an expanding capital and maintenance program and the expansion of the Grid Modernization function. This function will allow the utility to forecast, understand, and manage a more complex system as it becomes increasingly decarbonized, decentralized, and digitized. Incremental resources, new skillsets, and third-party support is required within the planning and engineering functions in support of the above needs;[47]
- The Work Execution program will have an average annual increase of 5 percent over the 2025-2029 rate period. The growth in this program is driven directly by the need for additional headcount to support a growing capital and maintenance program with increasing complexity to support the energy transition. The increase in headcount in key Certified and Skilled Trades and Designated & Technical Professional positions is required to enable internal work execution, whereas key resources such as field, project, and contract managers are required to support external work execution. Increases in training costs, tools and safety equipment, and personal protective equipment (“PPE”) are also required;

[45] Exhibit 4, Tab 2, Schedule 5.
[46] *Supra* note 38.
[47] *Supra* note 37.

- In addition, increasing resource and skill requirements and capabilities to support grid modernization results in higher costs across various business functions. For example, increasing the workforce of Control Centre Operations will be crucial as Toronto Hydro expands its grid and modernizes system operation through more sophisticated data analysis and automation, which will require more staff both to handle increasing volumes of work and deploy specialized skills and knowledge made necessary by the evolution of operational systems; and
- Inflationary pressures are also a key contributor to increasing expenditures over the forecast period across the various System O&M programs.

E4.2.7 Forecast Construction Work in Progress ("CWIP")

Table 11 below provide the 2025-2029 CWIP. Detailed explanations for capital expenditures are provided above and explanations for variances in In-Service additions are provided in Exhibit 2A, Tab 1, Schedule 1.

Table 11: Forecasted 2025-2029 CWIP ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Opening CWIP	456.4	533.7	589.1	596.4	636.6
Additions (CAPEX)	719.4	747.1	797.2	809.3	786.7
Deductions (In Service Additions)	(642.1)	(691.7)	(789.8)	(769.2)	(859.5)
Closing CWIP	533.7	589.1	596.4	636.6	563.8

/C

Note: Variances due to rounding may exist

E5.3 Load Demand

E5.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 120.9	**2025-2029 Cost ($M):** 217.1 /C
Segments: N/A	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Operational Effectiveness - Safety	

With increasing land development and growth in Toronto Hydro's service territory, the Load Demand program (the "Program") aims to alleviate emerging capacity constraints to ensure the availability of sufficient capacity to efficiently connect customers to Toronto Hydro's distribution system. In doing so, the Program also seeks to minimize the effect of load growth on existing customers. Toronto Hydro's investments in this Program enable the operation of its distribution system under first contingency scenarios, as well as the minimization of potential switching restrictions during summer peak conditions (which can impede the utility's ability to execute maintenance and capital work during summer months).[1] This Program is a continuation of the activities described in the Load Demand program in Toronto Hydro's 2020-2024 rate application.[2]

More specifically, the Program alleviates overloaded equipment and capacity constraints on the distribution system through:

- Load transfers to relieve station bus overloads;
- Feeder cable upgrades and load transfers to improve capacity and asset utilization;
- Equipment upgrades to increase available capacity and reduce the number of switching restrictions experienced during the summer peak; and
- Civil enhancements to remove system bottlenecks and support additional electrical capacity.

[1] " First contingency" occurs when any one primary feeder, transformer, or other critical equipment is lost, either due to a fault or planned outage.
[2] EB-2018-0165, Toronto Hydro-Electric System Limited Application (filed August 15, 2018, updated April 30, 2019), Exhibit 2B, Section E5.3.

E5.3.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Customer Focus	• Contributes to the sustainment of service connection targets established by the OEB (i.e. the Electricity Service Quality Requirements) for new residential, small business services, and high voltage services by undertaking targeted capacity upgrades in areas of high load growth in the downtown and Horseshoe area. • Contributes to customer satisfaction results by providing large customers flexibility in scheduling substation maintenance by reducing summer peak switching restrictions.
Operational Effectiveness - Reliability	• Contributes to maintaining Toronto Hydro's System Capacity measure, and reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: o Improving restoration capabilities and reducing customer interruptions by providing additional capacity or maintaining spare capacity through cable upgrades and load transfers; o Improving restoration capabilities in the downtown or Horseshoe systems by offloading highly loaded feeders; o Improving system reliability by reducing the risk of failures due to highly overloaded equipment through mitigation of expected bus overloads; and o Improving downtown reliability by maintaining or reducing the number of heat restricted feeders.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety performance objectives (as measured through measures like Total Recordable Injury Frequency) by reducing the failure risk of overloaded infrastructure to Toronto Hydro workers and members of the public.

E5.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Customer Service Requests, Reliability, System Efficiency

E5.3.3.1 Mandated Service Obligations

As per sections 3.3.1 and 4.4.1 of the Distribution System Code ("DSC"), Toronto Hydro is required to ensure its distribution system can support projected load growth while maintaining reliability and quality of service for customers on both a short-term and long-term basis. The utility must also connect new customers within the timelines prescribed by the OEB's service quality standards without adversely affecting the quality of distribution services for existing customers.[3] The OEB requires 90 percent of connections to be completed on time. Toronto Hydro achieved 99.9 percent of new residential and small business services completed within the prescribed timelines, and 99.1 percent of new high voltage connections completed within the prescribed timelines. The investments in this Program are specifically targeted to meet the OEB's service quality standards.

To satisfy these requirements, Toronto Hydro must maintain sufficient capacity on its system to keep pace with load growth and to ensure that its assets are not overloaded (i.e. an overloaded bus is defined as reaching 95 percent of its firm capacity under normal and emergency operating conditions). Highly loaded feeders in the downtown are defined as feeders that exceed cable ratings under contingency, assuming peak customer loads and a coincidence factor of 1 (i.e. all customers peak at the same time). In the Horseshoe, highly loaded feeders are defined as those with peaks of 400A, which is the standard planning practice as it leaves at least one third of a feeder's capacity available to support tie feeders under contingency.

The rapid influx of dense load in the downtown core and Horseshoe areas (see section E5.3.3.2 for more details) poses a challenge to Toronto Hydro's ability to meet its service requirements. Over the 2025-2029 rate period, Toronto Hydro expects that rapid growth will cause multiple buses to reach their rated capacity. The forecasted growth in the distribution system is based on the Toronto Hydro's Station Load Forecast. The actual demand will vary based on the actual realization of load on the system. This can depend on multiple factors and emerging trends such as electric vehicle

[3] Section 7.2 of the *Distribution System Code* requires Connection of New Services: low voltage (<750 Volts) within 5 business days and high voltage (>750 Volts) within 10 business days. Ontario Energy Board, *Distribution System Code* (August 2, 2023).

("EV") uptake and pacing of heating electrification. Section E5.3.5 Options Analysis explores how future energy scenarios can impact the requirements of this Program.

As discussed in greater detail below, critical parts of Toronto Hydro's distribution system (such as the Downtown and Central Waterfront Area in Table 4), which service a large amount of load or are experiencing high growth, are serviced by feeders that are already highly loaded and at risk of overloading in the upcoming years. Growth in these areas has been driven in large part by multiple storey residential condominiums, mixed use buildings and large commercial developments. If no action is taken to alleviate constraints, load shedding will be required during the summer peak period to mitigate the risk of failure from overloaded equipment. This involves dropping customer loads when the feeders or the equipment that supply them are overloaded so that a tolerable loading level can be maintained. Supplying customers through highly loaded feeders reduces the level of reliability, thereby causing Toronto Hydro to fail in meeting a top priority of these customers as identified through customer engagement.

E5.3.3.2 Customer Service Requests

Toronto Hydro receives customer requests for service connections every time there is a new residential, industrial, or commercial development, or when upgrades are required for an existing connection. Applications for Service are processed as part of the Customer Operations program.[4] In most cases, system planner input is required to determine how to service the customer in the most efficient manner. In constrained areas of the system, the utility's ability to respond to customer service requests within the OEB-prescribed timelines, without affecting the quality of service for existing customers, is largely dependent on the investments made in this Program.[5] Toronto Hydro utilizes the City of Toronto's land planning information to help assess which areas of the system are in most urgent need of additional capacity to accommodate customer service requests in a timely and cost-effective manner.[6]

Figure 1 shows the load additions (connection applications involving new or increased load) submitted to Toronto Hydro from 2018 to 2022 by geographical region. Figure 2 shows the resulting load impact in each region of the City.

[4] Exhibit 4, Tab 2, Schedule 8.
[5] *Supra* note 3.
[6] City of Toronto, *Development Pipeline 2022 Q2* (February 2023), « online », https://www.toronto.ca/wp-content/uploads/2023/02/92b5-CityPlanning-Development-Pipeline-2022-Q2.pdf

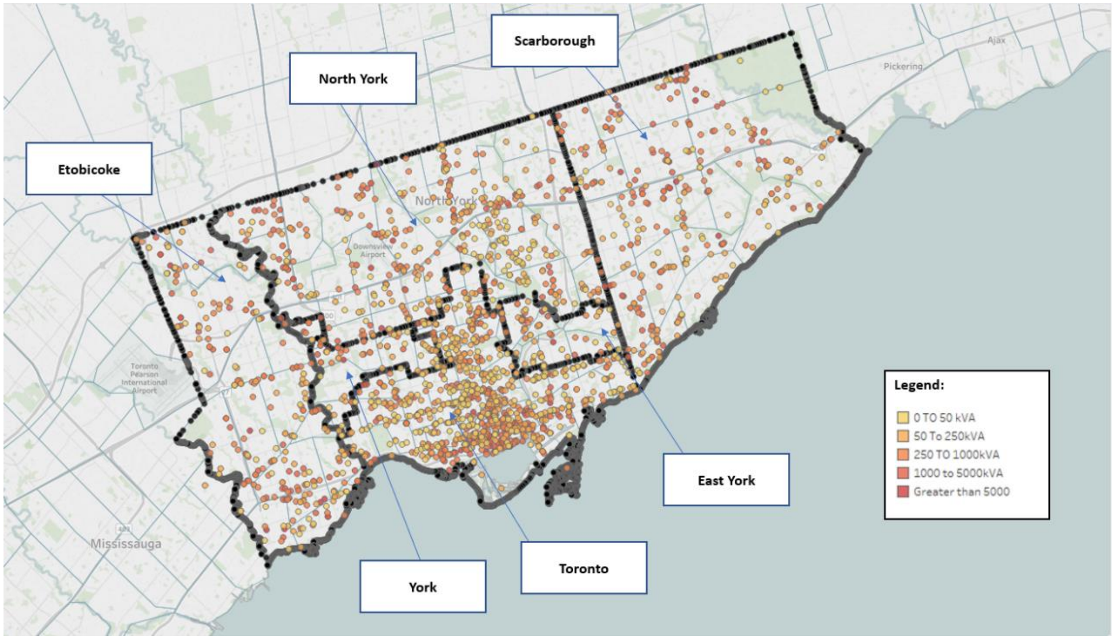

Figure 1: Load Additions in the City of Toronto during the 2018-2022 Period

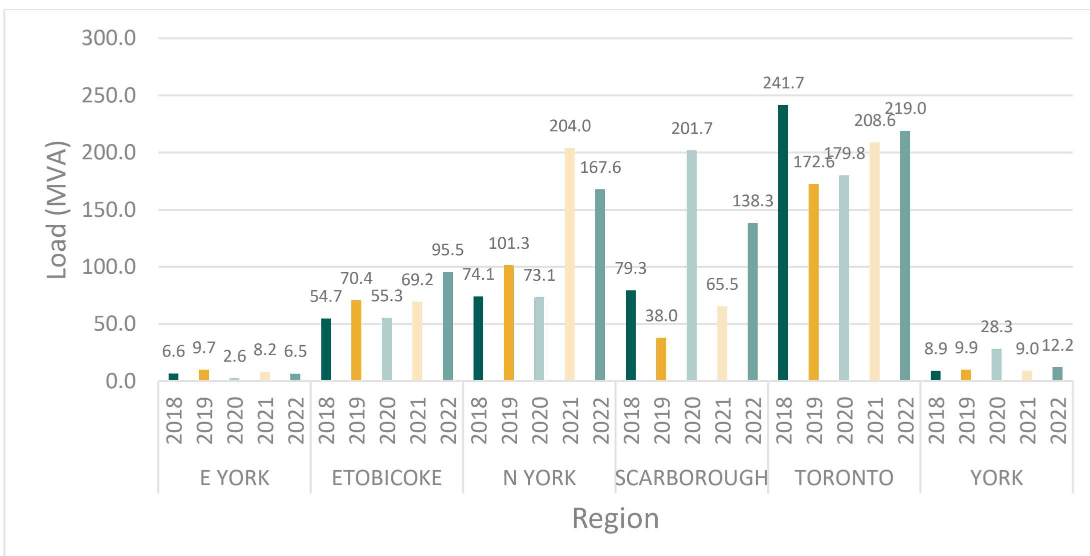

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Figure 2: Load Additions by Region during the 2018-2022 Period

The City of Toronto is experiencing an increase in development which is expected to continue throughout the 2025-2029 rate period. Table 4 below provides a summary of the projects submitted to the City of Toronto's Planning Division between 2017 and 2022 Q2, and Figure 3 is a map of the residential units proposed over this period.

Table 4: Proposed Projects in the City of Toronto (2017-2022 Q2)[7]

	Built	Active	Under Review	Total in Pipeline	% of Total	% of Growth Areas
City of Toronto	**622**	**879**	**912**	**2,413**	**100.0%**	
Growth Areas	**394**	**549**	**605**	**1,548**	**64.1%**	**100.0%**
Downtown and Central Waterfront	142	205	179	**526**	21.7%	31.5%
Centres	30	48	47	**125**	5.2%	14.5%
Avenues	149	209	279	**637**	26.4%	28.3%
Other Mixed Use Areas	73	87	100	**260**	10.8%	25.6%
All Other Areas	228	330	307	**865**	**35.9%**	

Source: City of Toronto, City Planning: Land Use Information System II

Development projects with activity between January 1, 2017 and June 30, 2022. Built projects are those which became ready for occupancy and/or were completed. Active projects are those which have been approved, for which Building Permits have been applied or have been issued, and/or those which are under construction. Projects under review are those which have not yet been approved or refused and those which are under appeal.

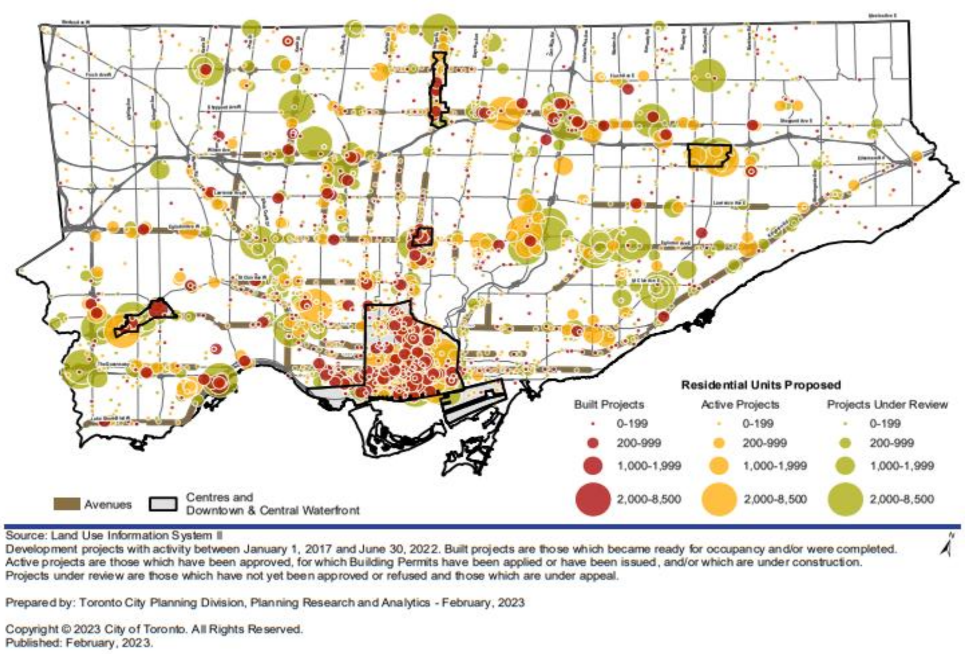


Figure 3: Residential units proposed (2017-2022 Q2)

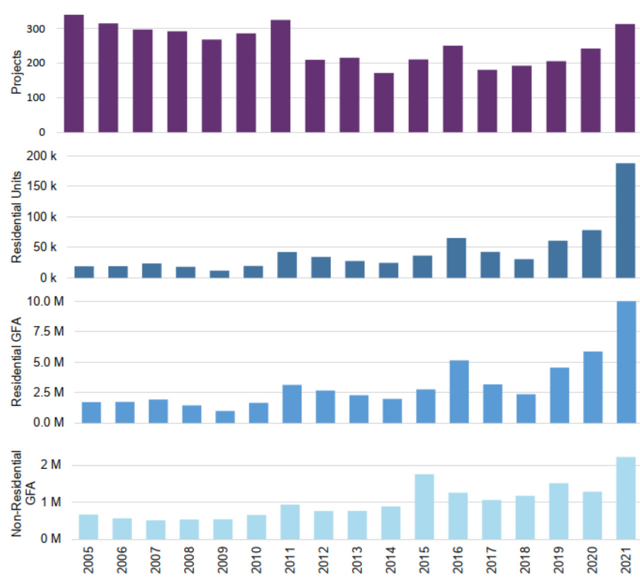
As illustrated in Figure 3, the majority of the growth is focused on the downtown system, particularly the Downtown and Central Waterfront area, where 43,513 residential units have been built as of the end of 2022 Q2 and 180,652 units are in the pipeline for future development. Another area

[7] *Supra* note 6.

experiencing strong growth in the downtown system is the Yonge-Eglinton Centre, with 38,361 units in the pipeline.

In the Horseshoe area, Sheppard East Subway Corridor, Etobicoke Centre, North York Centre, and Scarborough Centre have experienced development growth which is expected to continue: (i) in the Sheppard East Subway Corridor area, 22,699 units are in the development pipeline; (ii) in the Etobicoke Centre area, 17,575 are in the development pipeline; (iii) in the North York Centre area, 12,330 are in the pipeline; and (iv) in the Scarborough Centre area, 29,260 are in the pipeline.[8]

The number of projects submitted to the City of Toronto have remained relatively consistent over the years, ensuring a steady influx of projects and a healthy pipeline of projects. However, the number of residential units proposed and overall Gross Floor Area ("GFA") of the projects have increased substantially over the years, indicating each project has become larger and more complex overall. Figure 4 shows the trend of applications over the years. For Toronto Hydro, these large projects create single points of concentrated load that require detailed analysis and consideration when planning for their connections and managing system load overall.



Source: City of Toronto, City Planning: Land Use Information System II

Development projects submitted each year from 2005 to 2021, and the total number of residential units, residential GFA, and non-residential GFA proposed. Residential and non-residential GFA is in square metres.

Figure 4: Trend of Projects, Residential Units and GFA by Application Intake Year, 2005 to 2021

[8] *Supra* note 7.

Therefore, Toronto Hydro expects a steady stream of customer service requests for new connections over the 2025-2029 rate period and beyond. To meet these requests in a timely and cost-effective manner, and maintain reliability and quality of service for existing customers, Toronto Hydro must invest in infrastructure upgrades and load transfers to alleviate capacity constraints. In particular, Toronto Hydro must focus its efforts in the downtown and Horseshoe areas where concentrated growth is straining the distribution system by overloading station buses, feeders, and transformers.

E5.3.3.3 System Reliability and Efficiency

This Program aims to ensure that the system has enough capacity to restore customers during contingency events and that asset failure and loss of supply due to overloading are prevented. Operating assets above their rated capacity for prolonged durations increases the risk of failure and corresponding loss of supply to customers. These conditions can lead to the premature failure of primary overhead conductors and undersized legacy assets (e.g. underground paper insulated lead-covered “PILC” cables), that were installed over 35 years ago when standard trunk cables were approximately 30 percent smaller and had a 25 percent lower current capacity. Since 2012, Toronto Hydro’s distribution system has experienced 293 cable and splice failures on legacy PILC cable. Where cables are at the largest standard size, instead of cable upgrades to alleviate overloads on the feeders, load transfers to other feeders with capacity will be considered.

Overloaded assets pose reliability and public safety risks. For example, the temperature of conductors and cables increases when they are overloaded which reduces the conductor’s tensile strength.[9] Loss of the rated tensile strength can cause significant sagging of an overhead feeder line, which makes it more susceptible to external contacts and safety requirement violations.[10,11] Similarly, underground cables, such as the cross-linked polyethylene (“XLPE”) cable used in the downtown system, soften as their temperature increases, particularly in areas where the insulation is under

[9] K. Adomah, Y. Mizuno and K. Naito. "Probabilistic assessment of the reduction in tensile strength of an overhead transmission line's conductor with reference to climatic data." *IEEE Transactions on Power Delivery*, vol.15, pp.1221-1224, 2000.

[10] F. Jakl and A. Jakl. “Effect of Elevated Temperatures on Mechanical Properties of Overhead Conductors under Steady State and Short-Circuit Conditions.” *IEEE Transactions on Power Delivery*, vol. 15, pp. 242-246, Jan. 2000.

[11] Minimum Safety Clearance as in Toronto Hydro standard 03-2000 Overhead – Minimum Vertical Separations, where the exact clearance depends on the configuration of the pole, the type of attachments on it, and primary voltage.

mechanical stress (e.g. bends in the route), leading to deformation of the cable. This in turn can lead to electrical failures resulting in outages.[12]

E5.3.3.4 Addressing Drivers and Need

To meet the increasing need for capacity, ensure system reliability and efficiency, and meet the mandated service obligations, four types of work are carried out under this Program:

- **Bus Level Load Transfers**: load transfers between station buses to alleviate overloaded buses. [13]
- **Feeder Level Load Transfers and Upgrades**: transferring loads between feeders to alleviate overloaded feeders or upgrading undersized feeder trunks to the current standard.[14]
- **Equipment Upgrades**: carried out in areas like network vaults to increase unit size and associated capacity, which may reduce the number of switching restrictions experienced during summer peaks.
- **Civil Enhancements**: carried out in duct banks and egress cable chambers to enable capacity upgrade by allowing for more feeders to be installed.

1. Bus Level Load Transfers

Toronto Hydro plans to execute targeted load transfers on station buses that are expected to become overloaded based on Toronto Hydro's Station Load Forecast and those where opportunities will arise to redistribute load with adjacent station buses.[15]

Table 5 lists the specific station buses planned for bus level load relief during the 2025-2029 rate period, and Figure 5 shows the stations' locations. The station bus can be relieved by expanding the capacity of the bus through bus expansion, or by relieving the load of the bus through bus transfers. Bus transfers can be performed by transferring load between buses within the same station or to another station in the area. Additionally, bus balancing can be achieved during transfers to ensure that the bus capacity within transformer stations is optimized.

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[12] S. H. Alwan, et al. "Factors Affecting Current Ratings for Underground and Air Cables." *International Journal of Energy and Power Engineering,* vol. 10, pp. 1422-1428, 2016.
[13] **Bus** – A rigid, large conductor usually in substations, to provide a quick and convenient means of rearranging circuit connections to keep power flowing or to restore power after an outage.
[14] **Feeder** – A distribution circuit carrying power from a substation to customers. Feeders consist of circuits and other electrical equipment supported by civil infrastructure like poles and ducts.
[15] Exhibit 2B, Section E7.4.

The completion of Copeland TS Phase 2 under the Stations Expansion program will have the potential to enable load relief at Esplanade TS, Strachan TS, Windsor TS, Cecil TS, and Terauley TS. [16,17] For these stations, civil and cabling work to enable the transfers is planned to be undertaken before Copeland TS Phase 2 is energized, so that the full benefits of Phase 2 can be realized immediately upon its energization. Relief for Horner TS and Manby TS will follow in the 2025-2029 rate period after the expansion of Horner TS is completed during the 2020-2024 rate period.

Table 5: Station Buses Planned for Relief within 2025-2029

Station	Bus	Estimated Load to Transfer (MVA)	Area
Cecil	*A1-2CE*	10 - 20	Downtown
Copeland	*A1-2CX*	10 - 20	Downtown
Dufferin	*Note 1*	4 - 14	Downtown
Esplanade	*Note 2*	10 - 20	Downtown
Finch	*J-Q*	35 - 50	Downtown
Horner	*B&Y*	25 - 40	Horseshoe
Leslie	*B&Y*	15 - 30	Horseshoe
Manby	*Q-Z*	20 - 35	Horseshoe
Strachan	*A9-10T*	10 - 20	Downtown
Terauley	*Note 2*	10 - 20	Downtown
Windsor	*Note 2*	10 - 20	Downtown

/C

Note 1: Targeting bus supplying feeders in area bounded by St. Clair Ave, Queen Street W, Bathurst Street, and Keele St.
Note 2: Stations that are scheduled for Relief as part of Copeland Phase II expansion.

[16] *Ibid.* Copeland TS Phase 2 is expected to be completed by 2023/2024.
[17] Not all stations listed are addressed through the Load Demand program.

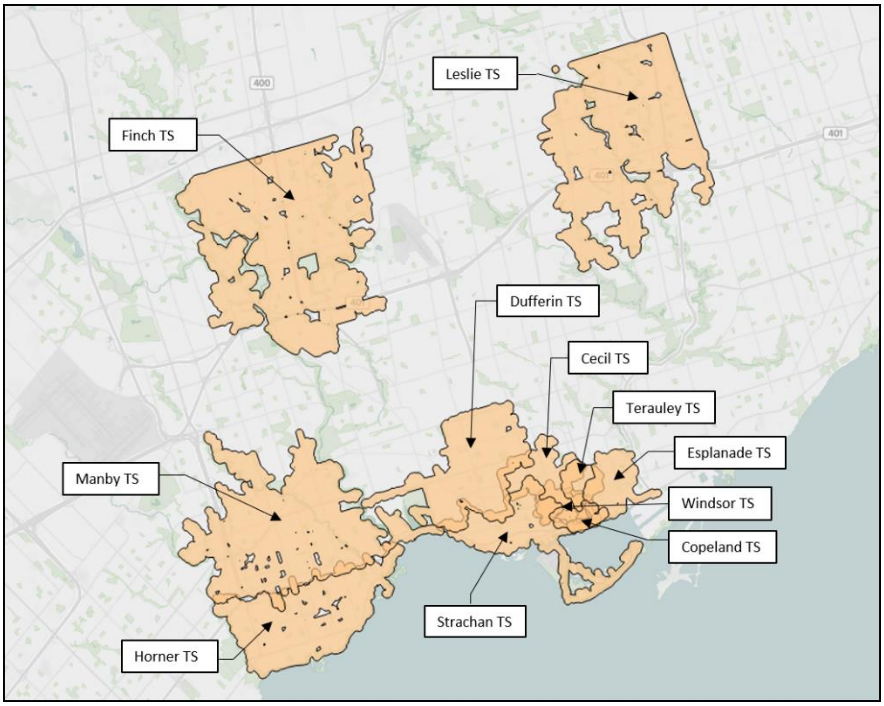

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Figure 5: Stations Targeted for Relief during the 2025-2029 Rate Period

If the buses outlined in Table 5 above are not relieved, it may not be possible to connect new customers to these station areas. As a result, Toronto Hydro may need to supply new service requests in the areas serviced by these stations from adjacent buses or stations, potentially resulting in system inefficiencies, materially higher connection costs, and longer timelines to complete the work. For example, capital contributions from connecting customers are required when revenue from their demand does not cover the cost of expansion work, as determined by the Economic Evaluation Model.[18] This may occur when significant expansion work is required for smaller loads.

Station bus load forecasts are re-evaluated annually.[19] Based on updated results, it may be necessary and prudent for Toronto Hydro to reprioritize load transfers. Some of the buses that Toronto Hydro plans to address in the 2025-2029 rate period originally appeared in plans for relief during the 2020-2024 rate period. For the reasons summarized in Table 6 below, these investments were reprioritized, with portions of the projects completed in the 2020-2024 rate period, and remaining portions to be addressed during the 2025-2029 rate period.

[18] Exhibit 2B, Section E5.1.3.1.
[19] Exhibit 2B, Sections D2.3, D3.3.1, and C3.3

When reviewing work to be targeted within the Program, Toronto Hydro will also consider work that can potentially be deferred using Non-Wire Solutions (NWS).[20] In the case of Manby TS and Horner TS in Table 6, the short-to-medium term capacity constraints of the buses due for load transfers were mitigated by identifying opportunities where local demand response ("DR") could be leveraged to reduce peak loads. The NWS program enables efficient and cost-effective load management, and can be leveraged in the 2025-2029 rate period in the prioritization of load transfers.

Table 6: Load Transfers projects continuing from 2020-2024 to 2025-2029

Station	Bus	Reasoning
Horner	*B&Y*	Based on regular re-evaluation of the proposed work in this Program, load transfers between Fairbank TS and Runnymede TS were prioritized ahead of these stations for the 2020-2024 period. The Horner TS and Manby TS load transfers were re-prioritized, and only the portions of the load transfers that required immediate attention were addressed in the 2020-2024 rate period. The remaining transfers are scheduled to be completed in the 2025-2029 rate period.
Manby	*Q&Z*	

/C

In order to transfer load from one station to another, Toronto Hydro often needs to install new feeders at stations with spare capacity. These stations are either existing ones with switchgear that have available capacity and feeder positions, or new stations where switchgear will be installed to create additional capacity. New civil infrastructure will be required if the existing infrastructure is in poor condition and requires rebuilding or if there are insufficient ducts to accommodate the new feeder installations. Extensive cable pulling and splices are then required to complete the transfer of customer loads from the existing feeders to the new feeders.[21] Load can also be transferred from one station to another by extending existing feeders to feeders with available capacity. In the Horseshoe distribution area, loads can alternatively be transferred by installing new switches or relocating existing switches. Therefore, the scope of work required when performing Load Transfer

[20] Exhibit 2B, Sections E7.2
[21] A splice is a joint created to maintain the connectivity between two cable sections or cable types. It is typically carried out when a longer cable is required, a branch is required or part of an old cable is replaced with a new cable.

projects vary depending on how much upgrades are required on existing civil and electrical infrastructure as mentioned above.

2. Feeder Level Load Transfers and Upgrades

Asset failures (overhead conductors, underground cables, and civil infrastructure) can lead to outages that last for hours due to the time it takes for crews to switch customers from faulted feeders to standby supplies. In first contingency scenarios, the distribution system is designed to continue operating at or below rated capacity in order to facilitate the transfer of load from feeders under a faulted condition to standby feeders. This allows for the restoration of power to affected customers from the standby feeder while the faulted feeder is being repaired. If feeder capacity is constrained, the number of customers the system can be served by the standby supply may be limited. Those customers that cannot be served by the standby supply would experience lengthy service interruptions, which would adversely impact reliability. Having available capacity on additional tie feeders allows for quicker restoration during more catastrophic events where cascading load transfers are required, because more operational options will be available to restore customers.

When the load on a faulted feeder exceeds the available rated capacity of standby feeders, restoration of power to affected customers is not possible until repairs are completed and, as a result, such customers would be at risk of prolonged interruptions. For example, in the overhead system, when a feeder faults and its standby feeder ties cannot be used due to the risk of overloading, the affected customers on the faulted feeder would remain without power until the failure is completely addressed.

In addition to the expected reliability improvement, having the flexibility (in the form of switching equipment) to de-energize feeders improves Toronto Hydro’s ability to execute planned capital and maintenance work by enabling the utility to switch customers onto their standby feeders.

When processing new customer connection requests, Toronto Hydro conducts an analysis to evaluate how customers are supplied, optimize the use of existing capacity, and accommodate new customers efficiently. This analysis helps to determine areas requiring feeder level transfers to enable available capacity. In some instances, Toronto Hydro may decide to perform feeder level load transfers if the assets are already at the maximum standard cable size, or if the bus that supplies the feeder has available capacity but feeder loading is not balanced.

Performing a load transfer between feeders to accommodate a new customer is often the preferred alternative when possible as it can be carried out at a lower cost than upgrading the feeder. Similar to bus level load transfers, feeder level upgrades and load transfers provide value to current and future customers by ensuring that the system can support rapid growth in a timely and cost-efficient manner, without adversely affecting the quality of service for existing customers.

The sections that follow describe the Feeder Level Load Transfers and Upgrades planned on the 27.6 kV system, which serves the area of the system commonly known as the Horseshoe and the work planned for the 13.8 kV system, which serves the downtown core.

a. The Horseshoe System

To manage load growth in the Horseshoe area, Toronto Hydro plans to undertake capital investments in feeder level load transfers and feeder upgrades in the Scarborough, Etobicoke, and North York areas. Load transfers are preferred over feeder upgrades because the overhead system, which serves the majority of the Horseshoe area, has multiple tie switches making it easier and more cost-effective to transfer load between adjacent feeders. Cable upgrades are also performed in the Horseshoe when segments along the cable are undersized and limit the overall carrying current capability along the feeder. Such undersized segments along feeders are typically legacy aluminum cables which are upgraded to standardized copper cables to raise the maximum current carrying capacity to 600 A, which is an increase of up to 100 A in capacity, or about the equivalent of 2300 customers.[22] There are 111 Horseshoe feeders forecasted to be highly loaded by 2029 and Toronto Hydro plans to relieve /C
15 of the highest priority feeders (i.e. those with the highest level of overloading) through feeder /C
transfers or cable upgrades in order to manage the forecasted growth over the 2025-2029 rate period. Toronto Hydro will continuously assess actual feeder conditions before investing in any upgrades or transfers.

b. The Downtown System

The majority of the underground 13.8 kV system in downtown Toronto is configured as a dual radial scheme. Customers are supplied by two feeders: one that provides their normal supply and the other that operates as standby supply. In areas that have experienced rapid load growth, customers now have an overloaded standby supply, with additional overloaded feeders expected during the 2025-

[22] Exhibit 2B, Section E7.1.

2029 rate period. If there is a loss of supply in these areas, overloaded standby supply means that there are less options available to restore customers.

Toronto Hydro analyzed all downtown feeders to determine which feeders are projected to be highly loaded during the 2025-2029 rate period based on the Toronto Hydro's Station Load Forecast. By the end of 2029, there is projected to be 178 highly loaded feeders in the downtown system /C (representing approximately 27 percent of downtown feeders) if no work is done to address them. /C

As a result, in the 2025-2029 rate period, Toronto Hydro plans to relieve 64 of the highest priority /C feeders in the downtown area to manage load growth and continuously meet system reliability goals through feeder upgrades and feeder load transfers. By comparison, in the 2020-2024 rate period, Toronto Hydro relieved 18 highly loaded feeders through cable upgrades and transfers. This increase in the number of highly loaded feeders planned for relief is due to the rapid growth of the number of highly loaded feeders. Toronto Hydro will continue to prioritize the feeder transfer and upgrade projects based on the latest information on how load is materializing on the system and regular re-forecasting efforts.

Toronto Hydro plans to upgrade undersized feeder trunks to the current standard (500 kcmil TRXLPE) to maximize previously stranded capacity for feeders that are becoming highly loaded. For example, feeder A62A supplies 16 customers in and around the downtown core along Dundas St. E. to Jarvis St., and along Yonge St. from Dundas St. to Richmond St. Many of these customers are key account customers operating commercial complexes, outdoor public and event spaces, university campus services and government locations. This feeder is at capacity due to the presence of undersized 2/0 trunk cable. An upgrade to 500 kcmil TRXLPE cable will more than double the capacity on the feeder, allowing for 5 MVA of customer load to be added.

In the downtown area, because of congested civil infrastructure nearing end of life or built to older civil standards (therefore unable to accommodate the latest cable standards), it is often necessary to rebuild or expand the existing civil infrastructure when upgrading underground cables. Figure 6 below shows a congested legacy square duct unable to accommodate the current standard trunk cable, therefore limiting the overall capacity of feeders using this civil route. In addition to capacity constraints, the clay duct tile is typically collapsed, and in need of rebuild. Such legacy square ducts span over 4.6 kilometres and contain feeders supplying in the downtown area including hospitals, as well as other large customers.

Toronto Hydro plans to complete upgrades or rebuilds of this existing civil plant as part of this Program. It is estimated that 50 percent of the length of the civil route for each planned feeder upgrade will need to be upgraded as well to accommodate the new electrical. This includes cable chamber and duct bank rebuilds.

Figure 6: Example of a Legacy Square Clay Tile Duct

New feeder installations are also required when an area requires greater capacity than is available with existing feeders. These new feeders are then utilized to relieve the existing load and service any upcoming demand in the area. In cases where bus expansion is not possible at the station, the feasibility of expanding the bus with new feeder positions at nearby stations are explored. The new feeders from nearby stations will supply the load from the station that has reached or exceeded its capacity. One instance where new feeders from a station are required to offload a nearby station is Richview TS offloading existing feeders from Finch TS. The area which Finch TS services, spanning from Hwy 27 to Jane St, and Steeles to South of Hwy 401, have feeders that are highly loaded and require support and relief to accommodate upcoming load growth in the area. With Finch TS already highly loaded at the bus as well, new feeders from Richview TS, which is a nearby station south west of Finch TS, will support by offloading the highly loaded feeders from Finch TS.

3. Equipment Upgrades

Due to capacity constraints, Toronto Hydro is forced to impose summer switching restrictions during peak load conditions, such that certain feeders cannot be taken out of service during those periods.

If restricted feeders are taken out of service, their corresponding standby infrastructure (standby feeders, adjacent network units) will be overloaded. This practice constrains Toronto Hydro's ability to complete new customer connections and hinders its ability to plan and execute other capital maintenance work in a timely and efficient manner.

Heat restricted feeders are feeders flagged as at-risk of overloading their standby feeders or network equipment during a contingency situation during peak hours or summer days. This means that these feeders should not be taken out of service (at a certain temperature) in the summer months in order to avoid overloading other infrastructure under contingency. Toronto Hydro is seeking to maintain or reduce the number of restrictions on its system so as to enhance its ability to take feeders out of service for maintenance or capital work. Cable upgrades and load transfers may be used as strategies to relieve summer switching restrictions on the primary feeder level. The equipment upgrades as part of this Program aim to upgrade undersized network units that are at-risk of overloading and may create summer switching restrictions. An example of a network unit is shown in Figure 7. A network unit consists of a primary switch, network transformer, and network protector.

Figure 7: An Example 500 kVA Network Unit

In the downtown core, network units are fed from various primary feeders, and are interconnected on the secondary side (i.e. low voltage) of the distribution transformer in order to provide a redundant and highly reliable supply to customers. This configuration reduces the risk of customers experiencing interruptions during single contingency events. The network system supports reliability for customers in the downtown area, highlighted as a priority through customer engagement. Current key customers on the network system include hospitals, hotels, telecommunication and government buildings.

Through network equipment upgrades, Toronto Hydro will improve reliability for downtown customers on the network, highlighted as a priority in customer engagement. This will be done by reducing the number of potential network unit failures due to overloads; increasing the robustness of the network units by introducing the submersible design; and improving the amount of first contingency scenarios supported by reducing feeder restrictions. Network equipment that is at or over capacity must be upgraded to ensure that the network system operates without overloading. Overloading the network equipment can result in premature deterioration and failure of the assets, which in turn drives the need to impose restrictions during peak summer months. An additional benefit of upgrading existing overloaded network equipment is the introduction of a more robust submersible design that is capable of operating under flooded conditions. In locations where an upgrade is not possible because the network units are already at the highest size or if there are civil limitations, an additional transformer in a new vault may be installed or additional secondary cables may be added to support the highly loaded vaults.

In the 2020-2024 rate application, Toronto Hydro indicated its goal of reducing the number of summer switching restriction feeders to under 10, and has been doing so accordingly as seen in its progress presented in Table 7 below.

Table 7: Summer Restrictions by Year

Summer Restrictions	Year					
	2017	2018	2019	2020	2021	2022
Number of Feeders Restricted	21	9	6	4	4	5

To address the growth in demand of the number of network units under contingency, Toronto Hydro plans to upgrade 5 network units during the 2025-2029 rate period.[23] Toronto Hydro's goal is to continue maintaining the total number of restrictions to below 10 by during the 2025 to 2029 rate period. To achieve this goal, Toronto Hydro will also mitigate any potential primary feeder restrictions via cable upgrades and load transfers.

Where other equipment upgrades are required due to capacity needs based on forecasted growth on the feeders and not due to asset end of life, this Program will also upgrade capacity in order to manage growth and mitigate overloading assets.

4. Civil Enhancements

When certain stations are expanded or their switchgear is upgraded, Toronto Hydro must undertake supporting civil enhancement work in the egress cable chambers to enable additional capacity at the station. Table summarizes the expected station upgrades within the 2025-2029 rate period that may require civil egress rebuilds in order to optimally serve customers. These areas are shown geographically in Figure 8.

Table 8: Stations Requiring Civil Egress Rebuilds

Station	Switchgear Unit	Associated Work	Target Completion Year
Bridgman TS	*A1-2H, A7-8H*	*Switchgear Renewal*[24]	2026, 2029
Danforth MS	*A1-2DA*	*Switchgear Renewal*[25]	2028
Downsview TS	*New TS*[26]	*New TS*[27]	2029+
Duplex TS	*A1-2DX*	*Switchgear Renewal*[28]	2026
Manby TS	*B-Y, V-F, T3/T4, T13/T14*	*Switchgear Renewal and Transformer Renewal*	2027, 2029
Wiltshire TS	*A5-6WA*	*Switchgear Renewal*[29]	2029
Windsor	*A5-6WR, A3-4WR*	*Switchgear Renewal*[30]	2027, 2029

[23] The peak load reading of each network unit in the system was taken over the last 5 years and a growth consistent with the Metro Toronto Regional Infrastructure Plan was added to forecast the future overloads.
[24] See Exhibit 2B, Schedule E6.6 – Stations Renewal
[25] *Supra* note 24.
[26] See Exhibit 2B, Schedule E7.4 – Stations Expansion
[27] *Ibid.*
[28] *Supra* note 24.
[29] *Ibid.*
[30] *Ibid*.

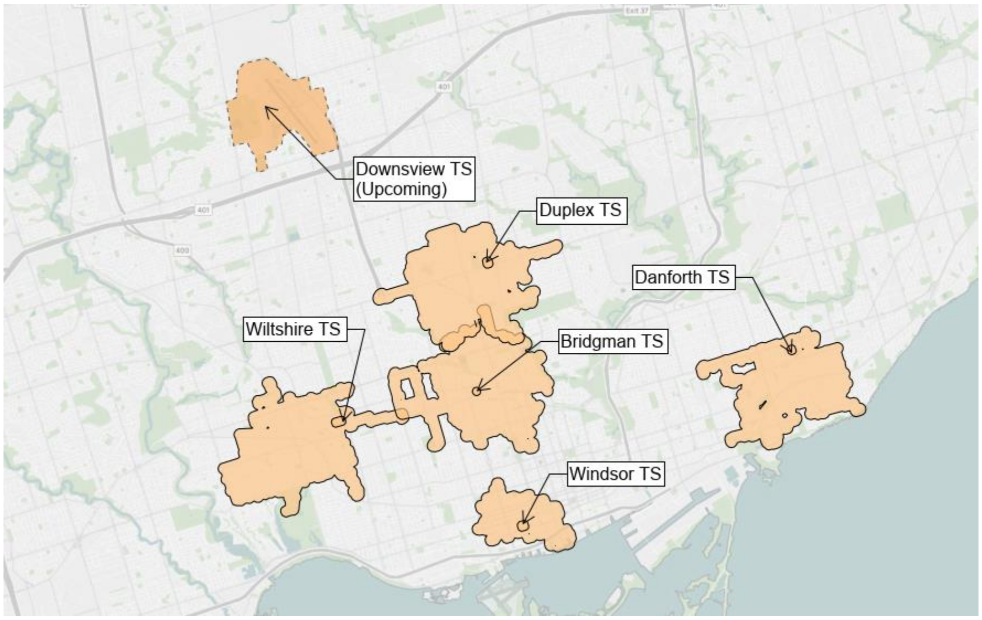

Figure 8: Stations Targeted for Civil Enhancements during the 2025-2029 Rate Period

Civil work can vary depending on the location of the asset expansion or renewal within the station, as well as the existing civil infrastructure in and around the station. For example, the Carlaw TS switchgear renewal scheduled for 2023 and 2024 will have new switchgear at the northeast corner of the station, egressing through the north cable pit. The majority of the Carlaw feeders already run north and northeast and those that are needed to the south must utilize cable chambers around the station to run south. This creates additional civil work around the station with added cable chambers and ducts being required. Another example during the 2020-2024 rate period is planned relief of Basin TS to the south to Carlaw TS due to the rapid growth around Basin TS including Ashbridge's Bay, GO Transit and the Port Lands developments. Additional feeders will need to be pulled south and the civil infrastructure must be upgraded and arranged in order to accommodate these plans.

In addition to supporting station renewal or expansion, civil infrastructure throughout the distribution system is required to be expanded or upgraded in areas that limit growth and electrical capacity. An example of infrastructure upgrade and expansion during the 2020-2024 rate period is along John Street between Front Street and Stephanie Street. The rebuilding of John Street addressed existing failing infrastructure and installed additional infrastructure required for growth. The scope consisted of rebuilding cable chambers, cable chamber roofs, vault roofs, vault rebuilds, collapsed ducts, and the expansion of ducts required for communication cables and contingency tie cables between stations. This rebuild ensured that existing key account customers fed from Windsor

TS would not be impacted by civil failure, enabled the connection of new customers in a timely manner, ensured that duct system can accommodate the fiber communication system, and enabled the ability to tie Cecil TS to Windsor TS to further mitigate against station contingency events. This was of great importance to the city because John Street connects many of Toronto's key cultural institutions to the waterfront. In the 2025-2029 rate period, Toronto Hydro is planning to invest in similar civil upgrades along Victoria Street, between Dundas Street and Lombard Street to rebuild legacy duct banks (i.e., square clay tile ducts) and undersized cable chambers that contain feeders supplying key account customers such as hospitals.

Apart from the capacity limitations, congested cable chambers increase the potential impact of chamber collapse on multiple feeders (and the significant customer load they supply in aggregate). For example, a cable chamber of 15 feeders can account for up to 75 MVA of customer load. Congested cable chambers also significantly impede the ability of crews to perform work safely.

E5.3.4 Expenditure Plan

Table 9: Historical & Forecast Program Costs ($ Millions)

	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Demand	24.0	29.7	30.8	22.6	13.8	43.5	46.4	38.1	42.7	46.4

/C

Table 10: Cost Breakdown by Type of Work ($ Millions)

	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Transfer (Bus)	8.7	13.6	15.3	16.5	4.9	22.59	15.11	17.81	15.97	8.69
Load Transfer (Feeder)	0.82	0.87	1.3	0.85	2.9	8.19	7.16	7.25	7.32	6.95
Cable Upgrades	7.3	5.9	8.3	4.7	2.4	7.72	12.04	12.20	12.31	2.57
Equipment Upgrades	0.32	0.10	0.42	0.23	0.0	-	0.39	0.79	0.40	0.42
Civil Enhancements	6.9	9.3	5.5	0.05	3.6	5.04	11.72	-	6.66	27.79

/C

The 2025-2029 expenditure plan is based on the specific work that is planned in each year. As is true with the 2020-2024 rate period, expenditures vary considerably from one year to the next due to the volume of work associated with the different activities undertaken by the Load Demand program (i.e. load transfers, cable and equipment upgrades, and civil enhancements).

During 2020-2022, Toronto Hydro has relieved capacity constraints on the system through the:

- Alleviation of 131 MVA on highly loaded buses through bus level load transfers or bus expansion;
- Reduction in the amount of highly loaded feeders by 10 through feeder level transfers and feeder upgrades;
- Improvement to the civil infrastructure associated with station expansion of Carlaw TS, Horner TS, Runnymede TS, Strachan TS, Terauley TS, as well as the upgrade to John street civil infrastructure between Front Street and Stephanie Street; and
- Maintaining the number of summer switching feeder restrictions to under 10.

These forecasts are re-evaluated annually, as described in the DSP – Capacity Planning, driven by information on expected new connections, on expected load transfers and voltage conversions, re-evaluated growth rate, and the previous years' weather corrected peak which is used as base for load growth.[31] Based on the annual re-evaluation of station bus load forecasts, Toronto Hydro fully expects that project scheduling will change. This is natural for a program such as Load Demand. For example, Toronto Hydro planned to address 28 highly loaded feeders through cable upgrades and load transfers. However, with the changing load growth needs of the system and reprioritization, 18 highly loaded feeders have now been planned to be addressed. Instead, additional investments were allocated to bus level load transfers with the following stations undergoing transfers that were not originally planned for: Runnymede, Carlaw, Leaside, George & Duke, Dufferin, and Terauley stations. This resulted in approximately an additional 100 MVA of bus level load transfers.

Investments in the 2025-2029 rate period aim to continue to relieve capacity strained areas in the City of Toronto. The plans are based on Toronto Hydro's Station Load Forecast. As described in section E5.3.3, this Program is made up of investments in station bus load transfer, feeder level load transfers and upgrades, network equipment upgrades and civil egress enhancements.

[31] Exhibit 2B, Sections D2.3, 3.2.1, and C3.3.

E5.3.4.1 Station Bus Load Transfers

The proposed work aims to provide load relief to the station buses that are expected to become overloaded in the next rate period due to growth, and which are located in areas where capacity is available at an adjacent station. Some of the planned bus load transfers are dependent on the completion of station expansions projects, such as the Copeland TS Phase 2 project. /C

The costs for bus level load transfers were forecasted using a cost per MVA transferred value, based on evaluations of historic project actuals. The cost per MVA can vary greatly for a bus level load transfer, depending on distance between stations involved in the transfer, location of feeders, and geographical constraints, such as the presence of bridges and highways, and civil conditions.

Load transfers in the Horseshoe area, which is generally served by the overhead system, can vary in /C cost depending whether the transfer requires tie switches between feeders, or whether expansion work as well is required. The cost would be considerably lower in areas where only a switch is required for a transfer compared to when expansion work would be required. Additional expansion work can include civil and electrical work in order to transfer load which can significantly increase the cost of the project.

E5.3.4.2 Feeder Level Load Transfers and Upgrades

As noted above, Toronto Hydro plans to undertake 64 feeders in the downtown area and **15** feeders /C in the Horseshoe area for relief through feeder upgrades and feeder load transfers during the 2025-2029 rate period.

Any cable upgrade to the trunk of a feeder is estimated to upgrade approximately 1,000 meters of cable in the downtown and 2,000 meters of cable in the Horseshoe, which will include civil upgrades for half of the distance. Civil upgrades include duct banks, cable chambers, and splices along the feeder route. The unit cost assumes 1,000 meters of upgrades per targeted downtown feeder because this is the average length of a feeder trunk, with each downtown feeder having a maximum spread of approximately 3,000 meters. In the Horseshoe, the average length of undersized aluminum cable egress that is targeted for upgrades to standardized copper cable is approximately 2,000 meters.

E5.3.4.3 Equipment Upgrades

Toronto Hydro plans to complete five network equipment upgrades during the 2025-2029 rate period in order to maintain its target of limiting summer switching restrictions under contingency scenarios to under 10.

For network equipment upgrades, the per unit cost was based on the cost to remove and install a new 750 kVA network unit, which was the most common upgrade seen in the 2020-2024 rate period.

E5.3.4.4 Civil Enhancements

Toronto Hydro plans to increase capacity and add new feeder cell positions at the following stations in the 2025-2029 rate period: Bridgman TS (downtown), Danforth TS (downtown), Downsview TS (Horseshoe), Duplex TS (downtown), Manby (Horseshoe) Wiltshire TS (downtown), and Windsor TS (downtown). Often, when station capacity is expanded and new cell positions are installed, additional feeders need new or expanded routes outside of the station via new or upgraded egress cable chambers and duct banks.

Toronto Hydro also plans to enhance its civil infrastructure in capacity constrained areas within the City of Toronto. The civil enhancement plan will address cable chambers and ducts in need of rebuild, and legacy infrastructure including square ducts which span over 4.6 kilometers, which limit the size of feeders to smaller diameter cables causing bottlenecks in capacity.

E5.3.4.5 Project Prioritization

Toronto Hydro considers a combination of several factors when prioritizing projects within the Load Demand program, including:

- **Load growth:** Toronto Hydro addresses areas of the system that are at capacity and that require significant investments to allow the connection of new customers. Forecasting of highly loaded areas is used to determine which projects should be prioritized.
- **Contingency operation:** Current limitations on the system prevent overloading during contingency operations. Projects that introduce additional capacity to allow the operators to remove these limitations will receive a higher priority.
- **Reliability:** For load transfer projects, sections of cable that require upgrading and that are on feeders with poor reliability or adjacent feeders will be given higher priority in order to improve future outage restoration times.

E5.3.4.6 Cost Management

Load Demand projects are continuously evaluated to ensure that the spending is in the appropriate areas. For example, the need for each bus level load transfer is re-evaluated annually to see if forecasts still hold true or if they should be modified. Load forecasts are the basis for determining if buses require relief. As seen in Table 6 above, two buses that were expected to be overloaded in the 2020-2024 rate period are being deferred to the 2025-2029 rate period. This allowed for other Load Demand work to be completed in their place since the transfers identified in Table 6 were no longer immediately required.

Additionally, Toronto Hydro enables cost savings through NWS. Peak shaving through Local DR can reduce immediate needs for bus level load transfers in this Program. During annual reviews of load growth forecasts, NWS may be deployed, if available, to temporarily defer bus level load transfer projects. In the 2025-2029 rate period, Toronto Hydro will aim to procure up to 30 MW of demand response capacity across three stations in the Horseshoe area and three stations downtown, which /C
could help defer or avoid about 25% of the total load planned to be transferred. For further details, /C
please refer to Section E7.2 Non-Wires Solutions.

By making capacity available by both electrical relief (via bus transfers, feeder transfers, feeder upgrades and equipment upgrades), and civil relief (via station enhancements), customers are able to be connected in an efficient manner. Without available capacity, infrastructure may have to be built using a suboptimal station (i.e. not in the area of the customer(s)) and using suboptimal and lengthy routes. Avoiding this work reduces the overall cost of connecting customers.

E5.3.5 Options Analysis

E5.3.5.1 Option 1: Do Nothing

Option 1 entails not planning any load transfers, equipment upgrades, or civil enhancements. This option allows Toronto Hydro to defer capital spending. Toronto Hydro anticipates that this option would reduce reliability and increase failure risk. Increasing loading stress on existing electrical infrastructure in heavily loaded areas under first contingency would shorten the operational life time of the electrical infrastructure. Rolling blackouts may be required during the summer to ensure that the peak loading remains under the capacity for the system, since no investments are being made to resolve the overloads during summer peaks. Areas of heavy loading will continue to experience increased loading, with the capacity to transfer loads under contingency decreasing. Following this option would impair the utility's ability to expedite upgrades to relieve heavily loaded infrastructure effectively and efficiently.

The addition of new high load customers in identified heavily loaded areas may exceed first contingency capacity, making system upgrades increasingly difficult and lengthy as Toronto Hydro would be unable to take feeders out of service for planned work if there is no viable standby feeder to accept the load. Finally, the exposure risk of customers in highly loaded areas to lengthy outages due to equipment failures or severe weather will be higher because of the inability to transfer load to standby or alternate supplies if capacity constraints are violated.

This is not a feasible option as it would give rise to a risk of non-compliance with DSC sections 3.3.1 and 4.4.1, which require Toronto Hydro to prudently and efficiently manage its distribution system, and address forecast load growth.

E5.3.5.2 Option 2 (Selected Option): System Investments Aligned with Toronto Hydro's Station Load Forecast

Option 2 aligns with the Toronto Hydro's Stations Load Forecast which applies a probabilistic approach to forecast the peak loads of all the buses of the stations within the city of Toronto. The output of the forecast is arranged to reflect summer and winter peaks due to the different characteristics between the two peaking seasons. The primary drivers for load growth for the 2025-2029 rate period are Customer Connections, commercial transportation electrification, EVs and hyperscale data centres.

This investment option would relieve station capacity by transferring load away from heavily loaded areas. This option also invests in cable upgrade, feeder transfers, equipment upgrades and civil enhancements in highly loaded areas with a focus of relieve overloads under a first contingency basis. As part of this option, Toronto Hydro will also consider utilizing NWS as a mitigating tool to defer bus-level load transfers where applicable.

Efforts under this option will provide capacity to expedite future upgrades and balance system loading, makes use of existing system assets by performing load transfers between highly loaded buses and feeders to lightly loaded alternatives, and allows Toronto Hydro to maintain full compliance with sections 3.3.1 and 4.4.1 of the DSC with regard to prudent and efficient distribution system management.

This is the preferred option since it addresses the capacity needs of the distribution system that are arising in the short to medium term, as well as considering expected electrification needs that have a significant impact to Toronto Hydro's distribution system. With this option, Toronto Hydro can comply with the DSC and improve customer service, reliability, and safety of the system.

E5.3.5.3 Option 3: System Investments Aligned with Future Energy Scenarios High Electrification Scenario (Customer Transformation Low)

This option looks to invest in accordance with the Future Energy Scenarios model Consumer Transformation Low ("CT Low") Scenario which accounts for high electrification needs while assuming low efficiency.[32] Based on the CT Low scenario, the amount of bus-level load transfers will increase by 217 percent when compared to Option 2. Additionally, compared Option 2, the number /C of highly loaded feeders will increase by 40 percent, the number of network equipment upgrades /C will increase by 120 percent and the expected stations requiring additional civil egress work will increase by 50 percent. Based on these increases, this will result in an increase cost of approximately $230 million when compared to Option 2. /C

This option would allow for extensive relief in line with a more aggressive load growth. However, there is a higher risk of overbuilding the system if aligning with this option. While it is not recommended to proceed with this option, this analysis does provide insight into the degree of variability in load growth depending on how electrification trends and customer behaviours materialize in the 2025-2029 rate period.

E5.3.6 Execution Risks & Mitigation

Several issues can present risks to the execution of the Load Demand program.

1. **Uncertainty of Future Load Growth**

Based on studies and analysis, the Station Load Forecast considered factors with a probabilistic approach when forecasting for peak loads of all Toronto Hydro buses of the station within the City of Toronto. Potential risks could arise based on future city planning changes or changes to redevelopment areas which could impact the load growth for the area. Such uncertainties can be mitigated by monitoring trends and updating forecasting accordingly and increasing flexibility when prioritizing and deploying work under the Load Demand program. Another strategy for managing

[32] Exhibit 2B, Section D4.

unexpected growth is the use of NWS such as local DR to shave peak loads. NWS can be implemented to incentivize customers to help reduce bus peaks. This type of NWS provides temporary relief, to provide flexibility to allow the time to implement more permanent solutions such as equipment upgrades or load transfers. Therefore, capital investments will still need to be made in the Load Demand program to support this growth.

2. Increasing Complexity of Projects

In order to complete load transfers and cable upgrades, feeders may need to be pulled or upgraded over long distances, utilizing several cable chambers and duct banks along the route. Records provide an indication of what civil costs can be expected for a Load Demand project; however, there can be unexpected rebuilding or expansion of civil infrastructure that is required. Civil inspections performed earlier in the project cycle can help mitigate any unforeseen project costs. Toronto Hydro has included preliminary inspections and design during up-front project creation in order to better scope out each project, leading to less variation in scope, costs and timelines as projects progress from planning to execution and construction.

3. Challenges Coordinating with Third Party Utilities

Moratoriums and third-party construction can limit and dictate the civil routes used in load transfers. Costlier solutions to bring capacity into an area may be required because we are unable to utilize more optimal routes where moratoriums exist or third-party construction is taking place. In these cases, potential impacts must be identified at the early stages of project planning and coordination must be sought and achieved.

E7.2 Non-Wires Solutions Program

E7.2.1 Overview

Table 1: Program Summary

Total 2020-2024 Cost ($M): $2.2	**2025-2029 Cost ($M): $22.5**
Energy Storage Systems 2020-2024: $1.2	Energy Storage Systems: $ 22.5
Local Demand Response 2020-2024: $1.0	Flexibility Services: OPEX only
Segments: Flexibility Services, Energy Storage Systems	
Trigger Driver: Capacity	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Financial Performance, Public Policy Responsiveness	

Toronto Hydro has been actively exploring how Non-Wires Solutions (NWSs) can support conventional utility planning since 2015, primarily through the Local Demand Response (LDR) program (now included in the Flexibility Services segment), but also through the deployment of grid-supporting Energy Storage Systems (ESS). In previous years, these two programs have been managed separately; going forward, they will be brought together under one Non-Wires Solutions program.

NWSs refer to operating practices, activities or technologies that enable the utility to defer the need for specific distribution or transmission projects, at a lower total resource cost, by reliably reducing system constraints at times of maximum demand in specific grid areas. Typically, these NWSs leverage the use of Distributed Energy Resources (DERs), often in partnership with utility customers, or with other enabling third-parties.

The NWS strategy for the 2025-2029 period is focused on being flexible and adaptable to help system planners respond to load growth while navigating the underlying uncertainty that stems from changing demand patterns and increased reliance on electrification. This strategy builds on Toronto Hydro's experience utilizing DERs to reduce peak demand, helping to defer grid expansions or, in most cases, avoid grid expansions should demand not materialize as expected (e.g., lower than expected demand, fluctuating demand). This approach can help utilities meet system needs while avoiding overbuilding, ultimately reducing the risk of stranded or underutilized assets. Given the scale of investment that will be required to meet high-levels of electrification, NWSs are viewed as additive to conventional utility expansion strategies, enabling Toronto Hydro to expand its planning toolbox to include additional strategies for keeping up with load growth.

The NWS program at Toronto Hydro has two broad streams:

1) **Flexibility Services**

   Flexibility Services at Toronto Hydro refers to programs that address localized distribution issues through targeted procurements with customers or other third-parties. The most well-established flexibility service program at Toronto Hydro is LDR, which has been running since 2015. For the 2025-2029 period, Flexibility Services will be expanded beyond standard 4-hour Demand Response (DR) to include other services that can address a demonstrated grid-need, such as shorter duration DR where appropriate.

2) **Energy Storage Systems**

   Energy Storage Systems at Toronto Hydro are an innovative tool to complement traditional utility technologies in addressing distribution grid challenges. For the 2025-2029 period, Toronto Hydro will focus on developing a scalable, demand-driven, ESS strategy that is responsive to distribution system needs and supports the pathway to renewable integration and electrification

Toronto Hydro's NWS strategy for 2025-2029 reflects the last eight years of experience in both LDR and the energy storage space. The vision for the future is a product of experience and reflection, resulting from facing and overcoming numerous challenges. The program is unique in that in contains both capital expenditures (ESS equipment), as well as operating expenditures (capacity or energy payments for DR capacity). These expenditures are outlined below.

E7.2.1 Flexibility Services

E7.2.1.1 Background and Future Vision

Toronto Hydro's vision for flexibility services is built upon its strong foundation of successfully deploying NWSs. Toronto Hydro, a leader in developing NWSs, intends to continue to evolve the opportunities and benefits afforded by NWSs.

Local Demand Response Overview

The LDR program is Toronto Hydro's flagship NWSs initiative. The LDR program was the first utility-driven NWS program in Ontario and has been deployed successfully since the 2015-2019 rate period. This program is designed to help address short-to-medium term capacity constraints at targeted transformer stations by identifying opportunities where DR, including behind-the-meter and customer-owned DERs, can be leveraged to support the broader distribution system cost-effectively.

The LDR program is a big step forward in evolving conventional utility station planning to include the consideration of NWSs alongside traditional "poles and wires" investments. This approach enables the utility to address capacity constraints using targeted deployment of DR, expanding the planning toolbox beyond conventional wires solutions when evaluating options to address short-to-medium term capacity needs.

Utilities regularly utilize information and data to prioritize infrastructure investment based on where the system needs it the most. Demand Response strategies can provide utilities with increased flexibility when determining which projects should be undertaken, which ones can be deferred to a later date, and which ones can be avoided entirely, ensuring optimal allocation of limited capital funds. This results in a more efficient use of capital, and in some instances, leads to avoiding capital expenditure all-together.

Since launching LDR in the 2015-2019 rate period, Toronto Hydro has demonstrated the ability to procure and deploy contractual DR capacity to support the grid. This experience has helped develop and grow capabilities in utilizing NWSs.

During the 2015-2019 period, Toronto Hydro ran LDR at one station located in the downtown core: Cecil TS. At the time, the utility was forecasting that capacity constraints would materialize on two busses at Cecil TS in 2020. Toronto Hydro used LDR to reduce summer peak demand by about 8 MW, helping to avoid anticipated capital investment. The anticipated capital investment was initially deferred to the 2025-2026 period. However, these upgrades were avoided entirely, as the load profile at Cecil TS evolved over the 2020-2022 period, resulting in a much different outlook which no longer necessitated station expansion. This pilot project is an example of how a utility can leverage customer-owned DERs to gain planning flexibility when dealing with investment needs that carry a high degree of uncertainty.

The Cecil TS LDR Pilot at a glance:

- Successfully contracted 8 MW of DR, working with commercial and institutional customers
- Reduced summer peak demand by 8 MW in 2018 and 2019
- Resource mix included back-up behind-the-meter generation and customer load curtailment activities
- 5-6 events per year, delivered over a 4-hour period (2pm to 6pm)

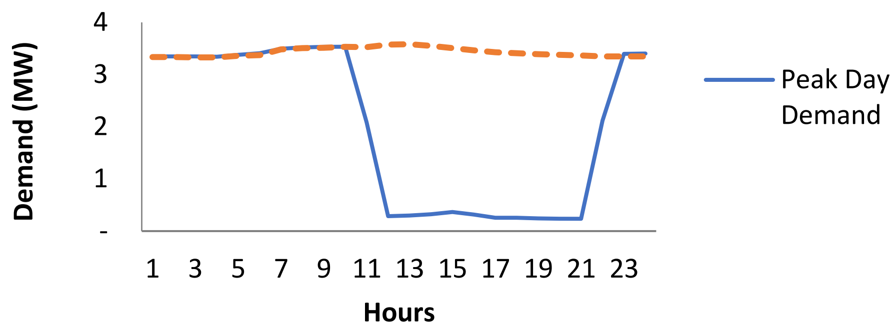

Figure 1. Sample LDR Event with a 3 MW Customer

For the 2020-2024 period, Toronto Hydro expanded the program to target two stations, Manby TS , and Horner TS. The details of this program are outlined in section E.7.2.2.4 below.

Evolution of LDR: Flexibility Services

For the next rate period, Toronto Hydro will build on the success of LDR to build a Flexibility Services program, which will expand to include services other than standard 4-hour DR. As with LDR, Flexibility Services are demand-side services that the utility purchases from customers and third-party vendors (i.e. energy services providers and aggregators) in order to address distribution system needs. These services allow the utility to work with customers and vendors to change where or when electricity is consumed, helping to level out peaks in demand. The goal is to find innovative ways to support electrification while enabling efficient use of capital, avoiding overbuilding the distribution system.

Table 2. Types of Flexibility Services:

Type of Service	Description	Use Case
Demand Response (DR)	Contractual arrangements with customers or aggregators for 4-hour blocks of load curtailment	Peak-shaving, capacity support
Short-Duration DR	Contractual arrangements with customers for 2-hour blocks of load curtailment. Enables participation from a wider variety of loads	Peak-shaving, capacity support

A key feature of the Flexibility Services program is the development of a competitive marketplace for the procurement of resources. To create this successfully, Toronto Hydro will:

- Identify areas in the system where demand-side approaches can help alleviate system constraints;
- Determine characteristics of capacity requirement (i.e. quantity, duration, seasonal need, expected number of activations);
- Conduct an options analysis to determine how these system needs can be addressed conventionally, and utilize this analysis to determine the capacity value and target price for capacity; and
- Communicate this information to prospective participants via an online platform; and
- Hold periodic auctions to procure capacity competitively, allowing Toronto Hydro to match available capacity with system needs.

One result of Toronto Hydro's 2020-2024 LDR program will be the creation of an online DR Capacity Auction tool, which enables the competitive procurement of DR capacity. This tool can be utilized in the 2025-2029 period to target several station areas (see Drivers section for more details). A prototype of the tool is currently under development in partnership with Toronto Metropolitan University's Centre for Urban Energy ("CUE").

E7.2.1.2 Outcomes and Measures

The Flexibility Services program works together with the Stations Expansion and Load Demand programs to ensure Toronto Hydro can supply growing customer demand while maintaining system reliability and improving grid resiliency. By leveraging customer-owned energy resources to offset peak demand, Flexibility Services provides incremental customer value in the form of grid optimization capabilities that were not traditionally available to grid planners and operators, while also providing an incremental source of value to current and prospective DER owners. This aligns with Toronto Hydro's broader modernization strategy, which aims to implement technologies and develop capabilities that will allow the utility to optimize the utilization and performance of its grid, ensuring distribution service and access remains as cost-effective as it can be while keeping up with anticipated demand pressures from electrification and the digitalization of the economy.

Table 3: Outcomes & Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Engaging with customers and enabling them to participate in the grid ○ Adding flexibility to the grid to enable efficient customer connections ○ Providing revenue opportunities for DERs, thereby encouraging DER uptake and integration
Operational Effectiveness - Reliability	• Contributes to maintaining Toronto Hydro's system reliability objectives by providing additional tools for managing and prioritizing capacity constraints.
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by acting as a bridging strategy to help to avoid (or defer) capital investments where demand is uncertain.
Public Policy Responsiveness	• Contribute to Toronto Hydro's public policy responsiveness objectives by: ○ Responding to the regulator's direction for utilities to consider and leverage NWSs where possible to drive rate-payer value ○ Reducing greenhouse gas (GHG) emissions by enabling the proliferation of energy storage, DERs, and grid-modernization ○ Enabling electrification by investing in additional capacity and operational flexibility

E7.2.1.3 Drivers and Need

Table 4: Segment Drivers – Flexibility Services

Trigger Driver	Capacity
Secondary Driver(s)	Reliability

The Flexibility Services program primarily helps complement conventional station expansion and load demand programs to address capacity constraints on the distribution system. Pressures such as densification, population growth, and electrification create constraints that need to be addressed either by building additional capacity, transferring load, or reducing load on the system via demand-side services.

These conditions are expected to intensify beyond 2024 as supported by the City of Toronto's long-term Precinct Plans[1] for both the downtown and the Horseshoe areas and by Toronto Hydro's 10-Year Station Load forecast (see Section D4 of the DSP). The Station Expansion program speaks extensively to the identified needs in Toronto Hydro's service territory over the 2025-2029 period.[2]

While the Station Expansion program at Toronto Hydro addresses large-scale, longer term load growth challenges through the provision of new or expanded transformer stations, the Load Demand program ensures that sufficient capacity is always available to keep pace with day-to-day load growth, preventing the overloading of system assets.

As described in the Load Demand program, a key tool for meeting capacity needs and ensuring system reliability and efficiency is bus level load transfers (load transfers between station buses to alleviate overloaded buses).[3] The Flexibility Services program directly supports Load Demand by identifying opportunities to defer or avoid these load transfers when and where it is appropriate.

To help identify where to target Flexibility Services, both long-term planning (station expansion) and short-term planning (load demand) needs are considered to identify opportunities for NWS support. Factors that are considered when selecting a target area include high-levels of projected growth, large customer connections (e.g. data centres), high levels of load connections generally, and projections for electrification drivers, e.g. electric vehicle adoption. For the 2025-2029 period, the Flexibility Services program will target six stations in in Toronto Hydro's service territory: three in the Horseshoe (Finch TS, Manby TS, and Leslie TS) and three in the downtown (Cecil TS, Strachan TS, and Copeland TS). /C

It should be noted that a key feature of the Flexibility Services program is that it can easily adapt in terms of scope and location to meet the most pressing system needs. The current focus on the six identified stations is due to the high potential for NWSs to defer capital expenditure. This is based /C on the identified system needs, as well as an assessment of current and expected future DER capacity. These stations have emerged as ideal target areas because:

- High levels of load growth are expected over the next ten years;

[1] City of Toronto, *How Does the City Grow?* https://web.toronto.ca/wp-content/uploads/2017/08/9014-How-Does-the-City-Grow-April-2017.pdf
[2] Exhibit 2B, Section E7.4.
[3] Exhibit 2B, Section E5.3.

- Large-scale developments (including City Downsview Development adjacent to Finch TS) are expected to materialize in the near-term; /C
- Currently has a high-penetration of large Key Account customers, some of which have DER capacity that could be utilized to provide distribution grid services; and,
- It has been identified as an area that will require up to 130 MVA of load-transfers in the next rate-period.

Toronto Hydro plans to execute targeted load transfers on station buses that are expected to become overloaded based on Toronto Hydro's Station Load Forecast and those where opportunities will arise to redistribute load with adjacent station buses.[4] Figure 2 shows all stations that are targeted for bus-level relief in 2025-2029. Some of these stations are excluded (i.e. Dufferin TS, Terauley TS, Esplanade TS, Horner TS and Windsor TS) as the transfers are either carry over projects from 2020-2024, or projects where overloading is not the primary driver.

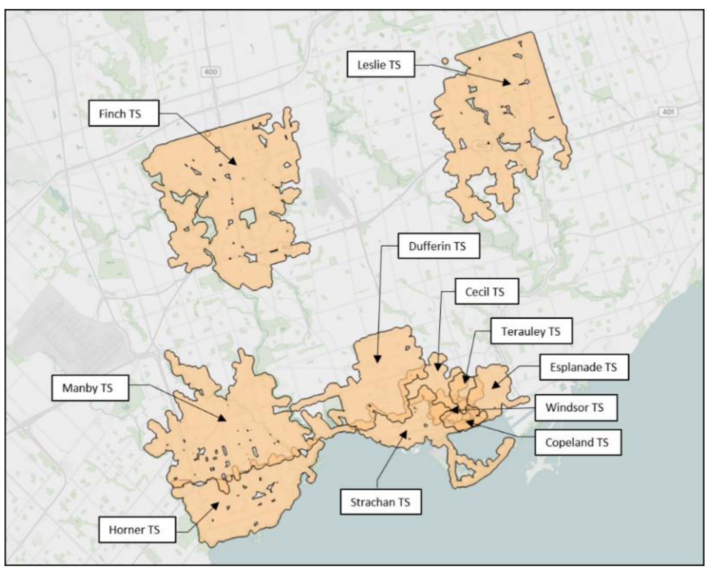

Figure 2: Stations Targeted for Bus-Level Relief during the 2025-2029 Rate Period

/C

[4] Exhibit 2B, Section E7.4.

The current shortage of feeder positions or bus capacity makes it difficult to connect new customers to an optimal supply point within the station service area. In this case, feeders are extended outside the boundary of the station service area, which may require the construction of additional civil infrastructure. Furthermore, load transfers between feeders could also be required to accommodate new customer connection from the nearest available feeder.

Table 5. Load Transfers Anticipated at Target Stations in 2025-2029 Period

Station	Bus	Estimated Load to Transfer (MVA)	Area
Cecil	A1-2CE	10 - 20	Downtown
Copeland	A1-2CX	10 - 20	Downtown
Finch	J-Q	35 - 50	Horseshoe
Leslie	B&Y	15 - 30	Horseshoe
Manby	Q-Z	20 - 35	Horseshoe
Strachan	A9-10T	10 - 20	Downtown

Flexibility Services targeting these stations can provide temporary relief, giving planners flexibility to determine whether load transfers will become necessary. As part of the Load Demand program, station bus load forecasts are re-evaluated annually and informed by up-to-date system conditions, new connections, and updated weather corrected load forecasts. Based on the outcome of this evaluation, the need for specific load transfers can either be escalated in priority or deferred. This provides Toronto Hydro with the opportunity to explicitly consider and use NWSs to help avoid a portion of these load transfers when possible[5]. This consideration will inform where to focus NWS procurement efforts on an annual basis utilizing the appropriate, competitive process. This has been an auction process in the 2020-2024 period; however, as part of the ongoing evolution of this program, Toronto Hydro will continue to consult with stakeholders to refine and update the procurement mechanism, ensuring maximum participation from customers and aggregators.

Given the range of expected load transfers in Table 5, Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the areas served by the six target stations. This could help avoid about 25% percent of the total load required to be transferred in these areas. This translates to

[5] As noted in the Load Demand narrative (Exhibit 2B, Section E5.3.), Manby TS and Horner TS, which were originally planned for relief in the 2020-2024 period, have been deferred to the 2025 period, in part due to the Local Demand Response program.

avoided capital expenditure in the range of $10 million, at a projected cost of about $5.7 million in operating expenditure. Further details about costs are provided in the Expenditure plan.

E7.2.1.4 Expenditure Plan

Table 6 and Table 7 below summarize the LDR Program plan for 2020-2024.

Table 6: 2020-2024 CIR – LDR ($ Millions)

	2020	2021	2022	2023	2024	Total
CAPEX	1.0	-	-	-	-	1.0
OPEX	-	0.8	0.8	0.8	0.8	3.2

Table 7: Actual and Bridge Costs- LDR ($ Millions)

	Actual			Bridge	
	2020	2021	2022	2023	2024
CAPEX	1.0	-	-	-	-
OPEX	0.2	0.2	0.2	0.7	0.7

For the 2020-2024 period, Toronto Hydro has moved the majority of the capital allocated to the LDR battery system into the ESS program to plan and track all ESS projects under one program. The remainder of the total 2020-2024 Local DR program cost (e.g. incentives, labour) is not capitalized (i.e. OPEX). The majority of the costs are related to DR capacity payments ($1.4 million), and the remainder of the costs ($0.6 million) are related to program administration, legal costs, and consulting costs. Details about costs are provided in the program description below.

1. 2020-2024 Local Demand Response Program

For the 2022-2024 period, Toronto Hydro has continued to advanced capabilities in the NWS space, building on the work done in the 2015-2019 period at Cecil TS. For this period, the LDR program targeted two transformer stations (TS): Manby TS and Horner TS. These stations were selected based on specific needs; Manby TS has been reaching capacity on two busses for several years and overloading at Horner TS has been forecasted in the near-to-mid term. These capacity issues were identified in Toronto Hydro's 2015-19 Custom IR Application[6] and Hydro One's 2016 Regional Infrastructure Plan for the Metro Toronto Region.[7]

Several load transfers north to the Richview TS have been completed. Further transfers are difficult due to the distance between the stations and a lack of remaining overhead corridors running north-south. Load transfers to neighbouring stations to the east cannot be easily achieved due to capacity constraints at Runnymede TS, the Humber River posing a geographical barrier, and different system voltages (13.8 kV vs 27.6 kV). Load transfers to the west and south are not possible because the Manby TS and Horner TS are on the boundary of Toronto Hydro's service territory. Due to limited space at Manby TS for expansion, work has been underway to expand capacity at Horner TS. This new capacity will be utilized to relieve Manby TS in 2025. In the meantime, while the expansion work is undertaken, LDR has been leveraged to provide increased flexibility in the Manby TS and Horner TS area. As a result, some additional load transfers from Manby and Horner TS have been avoided over this rate-period and it is expected that this will continue to be the case until 2025, when load will be permanently removed from Manby TS to Horner TS.[8]

As noted, the majority of the LDR program costs are related to capacity payments for demand response ($1.4 million), and the remainder of the costs ($0.6 million) are related to program administration.

The capacity payments made to DR providers are benchmarked against the cost of additional load transfers that would have otherwise been required at Manby TS and Horner TS. It was estimated that the capital cost of executing 10 MW of load transfers from Manby TS or Horner TS to adjacent stations would be in the range of $4 million. Utilizing LDR to avoid these load transfers between 2023-2025 has effectively helped manage demand in this area until the expansion of Horner TS is complete and a permanent transfer can be made from Manby TS in 2025. As such, it was important to ensure that the total cost of LDR (capacity payments + admin) was well below the cost of the wires solution on a net present value basis. The maximum capacity payment for LDR was benchmarked utilizing a discounted cash flow model comparing the cost of load transfers to the cost of LDR, and the capacity payment was further driven down as a result of competitive procurements. The LDR

[6] Toronto Hydro Custom IR Application for 2015-2019 (OEB File No. EB-2014-0116). https://www.rds.oeb.ca/CMWebDrawer/Record?q=CaseNumber=EB-2014-0116&sortBy=recRegisteredOn-&pageSize=400
[7] https://www.hydroone.com/about/corporate-information/regional-plans/metro-toronto
[8] Exhibit 2B, Section E5.3

program was initially projected to cost $4 million but will cost closer to $2 million over the current rate-period.

Evolution of LDR: Grid Innovation Fund Pilot Project

In late 2021, Toronto Hydro identified an opportunity to build on the LDR program planned for Manby TS and Horner TS to examine how Toronto Hydro and other distributors can work with the Independent Electricity System Operator (IESO) to better coordinate the use of DERs as NWSs in order to maximize value and lower resource acquisition costs. The IESO's regional planning documents indicated that capacity constraints were expected in the Richview-Manby transmission corridor starting in 2021. Transmission system upgrades will be necessary to address these capacity constraints. Due to project lead-time, the upgrades are not expected to come into service until 2025. The IESO is pursuing short-term measures, such as incremental Conservation and Demand-side Management (CDM) and DR, where feasible and cost-effective, to assist in reducing customer reliability risk until the transmission system upgrade can come into service.

Given the clear alignment of needs between Toronto Hydro and the IESO, Toronto Hydro partnered with Power Advisory LLC and Toronto Metropolitan University's CUE, to create a project that explores how to effectively and efficiently procure and deploy DR capacity to address overlapping distribution and transmission system level needs. This project is called the Benefit Stacking Transmission and Distribution Pilot ("Benefit Stacking Pilot") and is supported by the IESO's Grid Innovation Fund, and the Ontario Energy Board's (OEB's) Innovation Sandbox.

Currently, customers with load control capabilities or behind-the-meter DERs seeking to provide DR services interact with Toronto Hydro's distribution system (e.g., LDR) and the IESO-operated transmission/bulk system (e.g. as Market Participant) separately. There is limited opportunity for coordination between the two systems to maximize the benefit and value of the DERs.

The Benefit Stacking Pilot Project explores how customer-owned DERs can provide services to both the distribution grid and transmission/bulk system using an efficient single pathway that works with existing market mechanisms. By making it easier for DER owners to participate in multiple programs thereby maximizing the value proposition for DERs to provide non-wires services, it is anticipated that participation levels would increase which would then, over time, drive down resource procurement costs. A key deliverable of the Benefit Stacking Pilot Project will be an analysis of the resulting rate-payer value of the dual DER participation.

Toronto Hydro will simulate offering LDR capacity into the IESO market, unlocking additional revenue streams and system benefits, often referred to as "benefit stacking". Toronto Hydro will also simulate the utilization of the LDR resources in the IESO's real-time markets, testing how Transmission-Distribution system coordination can be undertaken to avoid conflicting dispatch instructions between the two levels. The costs of the simulation are being funded through the IESO's Grid Innovation Fun (GIF). The pilot explores current barriers to LDC-IESO coordination, seeks to improve overall visibility for both LDCs and the IESO with respect to DR resource activities and identify pathways for better coordination, leading to more efficient dispatch at both levels.

2. 2025-2029 Forecast Expenditures

Given the range of expected load transfers in Table 5, Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the areas served by the six targeted stations. This could help avoid about 25% of the total load required to be transferred in these areas. This translates to an avoided (or deferred) capital expenditure in the range of $10 million (at minimum), at a projected cost of about $5.7 million in operating expenditure. /C

Because Flexibility Services are market-based, the goal will be to again run competitive procurements that enable Toronto Hydro to drive down the cost of contracting for DR. The anticipated spend of $5.7 million dollars is based on the current market value of demand response in the LDR program, which is $700/MW-day for the summer 2023 period. However, each time a procurement is planned, Toronto Hydro will go to market to determine if the NWS is cost-effective as compared to the wires solution. To determine the cost-effectiveness, the cost of the specific load transfers would be compared to the procurement of DR over a specified period of time. This analysis determines the reference price for the DR, and the competitive procurement seeks to further lower this price through competition.

Table 8. Segment Unit Scenarios over 2025-2029 period

Segment	Cost per unit	Target Capacity	Projected cost	Capital Avoidance & Deferral
Flexibility services	$0.7M/MW	Up to 30 MW	$5.7M	$10M

Table 9: 2025-2029 CIR – Flexibility Services ($ Millions)

	2025	2026	2027	2028	2029	Total
Flexibility Services (OPEX)	0.2	0.9	1.1	1.6	1.9	5.7

It is anticipated that Toronto Hydro will spend the first year of the 2025-2029 rate period prioritizing targeted stations, setting capacity targets, and developing procurement processes and documentation. Between 2026-2029, Toronto Hydro will set the following procurement targets:

- 2026: 10 MW
- 2027: 15 MW
- 2028: 25 MW
- 2029: 30 MW

Program operating costs are based on an assumed capacity payment of $700/MW-day plus $200,000 per year for labour and operations. It is highly likely that the $700/MW-day figure will be driven down through competitive procurements over time, which means the total program cost for Flexibility Services should be understood as a maximum cost that could be significantly lower. The 2020-2024 total program cost, for example, will come in at almost half of what was anticipated due to procurement efficiencies.

E7.2.1.5 Options Analysis

Option 1: Conventional Wires Options

As noted, the wires option for addressing short to medium term constraints in the areas served by the six targeted stations would include bus level load transfers. The range of expected load transfers /C are indicated in Table 5 above. Proceeding with Option 1 would mean failing to consider the role of NWSs when scoping and prioritizing those bus-level load transfers, losing the opportunity to defer or avoid anywhere between 23 percent to 54 percent of the total load required to be transferred in this area. Financially, this translates to a potential deferral or avoidance of up to $10 million in capital in the Load Demand program.

Additionally, proceeding without a Flexibility Services program would present a lost opportunity to build a more intelligent and interactive grid that can leverage local sources of generation and capacity resources to optimize grid performance. Doing nothing in the NWS space also presents a missed opportunity to work with customers and third-parties such as aggregators to find innovative solutions to distribution system problems. Customer engagement results indicate that it is important to customers to find ways to engage with the utility to better manage electricity usage, as well as to find efficiencies and cost reductions. The Flexibility Services program is directly responsive to this priority. Ultimately, the goal is to find the lowest-cost solution by exploring all possible options, including demand-side measures.

As demand becomes increasingly unpredictable due to increased uptake of DERs, Flexibility Services can help the utility navigate this uncertainty by providing a greater number of cost-effective options. This strategy checks an important regulatory requirement to evaluate alternatives to building traditional poles and wires infrastructure. It also enables a new lens on productivity – one that is focused on managing total system cost by optimizing how capital is allocated to address system needs more efficiently. In the Conservation and Demand-Side Management Guidelines, the OEB directs all utilities to explore NWSs alongside conventional wires solutions to provide cost-effective system options. Not proceeding with the Flexibility Services program would impact Toronto Hydro's ability to explicitly consider LDR options when addressing system issues.

Option 2: Continue with a small-scale LDR program that targets 1-2 stations

This option entails continuing with the LDR program as it is currently run in the 2020-2024 period, which means focusing on a modest capacity procurement of 10 MW and selecting 1-2 stations within the six identified station group to target. This option would help defer a small number of load transfers in this area, and would come in at a lowered cost of about $3.6 million (about $2 million less than the proposed plan in Option 3). There are several drawbacks to this approach. While it does cost less, it also provides a reduced opportunity for load transfer deferral (about $4 million versus the $10 million in the proposed option). Furthermore, in the current LDR program, the feedback from aggregators has been that smaller target areas make it very challenging and costly to acquire enough capacity to make participation in LDR economical from their perspective. Targeting 1-2 stations can mean a relatively small pool of possible participants, leading to more difficult procurement processes. From a program administration perspective, it does not cost significantly more to procurement 30 MW versus 10 MW, making a larger-scale program more cost-effective overall. Looking at the number of large loads and DERs connected in the areas served by the six selected stations, targeting a greater number of stations results in a larger opportunity to contract for flexibility services.

Option 3 (Selected Option): Create a Flexibility Services Program that the Six Selected Stations /C

Option 3, which is the recommended option, is to build a Flexibility Services program that works in tandem with the Load Demand program to address short-to-medium term load constraints across three stations in the Horseshoe area and three stations in the Downtown area of Toronto Hydro's service territory. This program will enable the explicit consideration of NWSs when evaluating and prioritizing bus level load transfers to address load growth and capacity issues in this area. /C

Because Flexibility Services are market-based, they also provide a crucial opportunity for utilities to leverage relationships with customers and third-parties to solve grid problems. Utilities have a great deal of system knowledge, data, engineering and operational experience; private sector organizations have developed excellent tools to help customers manage load behind the meter. Through working together, new and innovative ideas and solutions are generated that can help the sector better prepare for challenges ahead.

E7.2.1.6 Execution Risks and Mitigation

Procurement of Flexibility Services requires careful consideration of several factors. Over the last 8 years of running LDR, Toronto Hydro has navigated many challenges and come away with important lessons learned for how to manage risks.

Risk: Low participation levels in procurements

Going to market to procure flexibility services may not always yield successful results. This can be related to lack of resources, misaligned incentives, customer/participant confusion, or poor timing. To help mitigate these risks the following measures can be taken:

- Targeting station areas with a large penetration of large customers and existing DERs;
- Ensuring customers and aggregators are educated about programs through early participant engagement via program materials, webinars and one-on-one conversations;
- Creating programs that are straight-forward, with simple participation pathways and performance charges that create the right incentives without being too punitive; and,
- Ensuring aggregators have sufficient time to recruit customers.

Risk: Price discovery

One of the biggest challenges in the procurement of NWSs is price discovery. It is a given that the reference price for an NWS must be benchmarked against the cost of the wires alternative. However, the benchmark price may not always reflect the market price (i.e. the price the market participant is willing to take for their services). This process of price discovery presents many opportunities for learning and adapting in order to find the right balance of incentives. This includes not only the capacity or energy payment, but also any performance charges that may apply to ensure the services are reliably delivered. Some of the risks involved could include:

- Overpaying for services
- Setting prices too low resulting in low uptake
- Creating performance charges that are too lenient, resulting in poor performance
- Creating performance charges that are too stringent, resulting in poor uptake

To help manage these risks, it is important to learn from other jurisdictions, work with stakeholders in advance to understand their costs, and remain nimble and adaptable by doing shorter term procurements while working to understand the market. The experience gained in the 2020-2024 period has been instrumental in learning what works and what does not work in terms of price discovery. These learnings will be taken into the next rate period.

E7.2.2 Energy Storage Systems (ESS)

E7.2.2.1 Background

Energy Storage Systems give utilities the flexibility to store energy and use it at a later time. As demand for system flexibility increases and battery technology costs decrease, ESS are expected to play a growing role in generation, transmission and distribution system planning. Utilities can utilize ESS in a variety of ways to support the grid. Toronto Hydro has been active in the energy storage space since 2017, with several existing projects, including behind-the-meter ("BTM") and front-of-the-meter ("FTM") installations outlined in Table 10 below.

Table 10. Existing Toronto Hydro ESS Projects

Project	Description/Use Case	Nameplate Capacity	Learnings
Bulwer BESS	FTM BESS supporting Cecil TS via peak-shaving	2MW/ 2MWh	○ BESS deployment and optimization utilizing Toronto Hydro's Energy Centre (DERMS) platform ○ Trouble-shooting operational challenges (e.g. faults) ○ Experience with creating baselines and measuring peak-shaving success on feeder
500 Commissioners	BTM BESS located at Toronto Hydro's facility, used for peak-shaving and GHG reductions	500kW/ 500kWh	○ Optimizing use of BESS to lower facility electricity costs and target GHG reductions via peak-shaving ○ Experience with maintaining BESS
TTC eBus	Customer-specific project providing charging support and peak-shaving	1MW/ 4MWh x 3	○ Understanding of connection requirements from other stakeholders, such as HONI and IESO, for large size BESS deployments ○ Optimizing BESS operation for EV charging use case ○ Understanding of design and commissioning requirements of features such as black start and dynamic transfer which are needed for islanding scenarios
Metrolinx Eglinton Crosstown LRT	Customer-specific project used for emergency back-up and load displacement	10MW/ 30 MWh	

Toronto Hydro has learned a great deal with respect to procuring, designing, constructing, commissioning, and utilizing BESS over the last six years. The Bulwer project, which is the only FTM BESS that is entirely owned and operated by Toronto Hydro, has been instrumental for developing knowledge around utilizing BESS to provide distribution-level grid support. This project was built in the 2015-2019 rate period and energized in January 2020. Over the 2020-2023 period, this project has been tested, commissioned, and transitioned to operations for deployment. This project helped Toronto Hydro develop:

- New processes for monitoring and controlling BESS assets on a daily basis,
- IT frameworks for integrating BESS software platforms safely and seamlessly with existing Toronto Hydro IT infrastructure,

- Methodologies for determining charging schedules, managing BESS state of charge, and measuring peak-shaving at the feeder level, and
- Maintenance of BESS assets.

Toronto Hydro also has experience with BTM BESS projects, including one at the 500 Commissioners street facility, and two that are located on customer sites (Metrolinx ECLRT and TTC eBus). These projects have also enabled building significant capabilities building, integrating and deployment of BESS. Based on current system needs, Toronto Hydro does not expect to own and install any BTM or customer-specific BESS projects in the next rate-period.[9]

<u>2025-2029 ESS Vision</u>

Toronto Hydro will build on its experience with BESS to move from individual pilot projects towards a standardized approach for design and deployment. The planned deployments will target areas with grid constraints to enable Renewable Energy Generation (REG) connections.

The BESS program has matured significantly as a result of the last six years of experience. Due to the new and innovative nature of this program area, the work achieved up until this point has been primarily pilot driven. Toronto Hydro has tried various approaches for procuring and siting BESS. One of the main challenges has been finding locations to install projects in areas where the grid has specific needs that could be addressed by BESS. Given the urban and dense nature of Toronto Hydro's service territory, land comes at a premium, and the use of this land must be assessed carefully to ensure asset siting decisions are prudent and cost-effective. Another challenge has been to integrate different types of BESS projects, each with unique software platforms and maintenance needs.

The strategy for the next rate period will explore a standardized approach for siting, designing and procuring BESS, utilizing small scale installations that enable siting on the right-of-way, similar to other distribution system equipment (e.g. pad-mounted transformers). This, in addition to standard BESS deployments, will help Toronto Hydro build a more scalable and streamlined BESS program in the future.

Based on current, identified distribution system needs that will be examined below, as well as Toronto Hydro's commitment to support the electrification and anticipated growth of renewable

[9] See for example: OEB Staff Bulletin, August 6, 2020 re Ownership and operation of behind-the-meter energy storage assets for remediating reliability of service. https://www.oeb.ca/sites/default/files/OEB-Staff-Bulletin-ownership-of-BTM-storage-20200806.pdf

generation in the city, the BESS portfolio will focus primarily on the renewable enablement use case in the 2025-2029 rate period. Several studies have shown that significant penetration of renewable generation can lead to destabilizing grid parameters.[10] In the renewable enablement use case, ESS can act as a load to prevent output curtailment from the renewable assets while ensuring a stable grid through controlling the minimum load to generation ratio (MLGR).

Based on internal studies, Renewable Enabling ESS can be installed anywhere along a feeder in order to help mitigate concerns regarding generation to minimum load ratio. Therefore, to avoid additional costs, the proposed ESS units could potentially be connected to existing Toronto Hydro assets (i.e. pad mounted transformers) that can accommodate the nameplate capacity, footprint and layout. If such assets and locations cannot be established, then new assets (i.e. transformer) will be installed to accommodate the proposed ESS.

Toronto Hydro is also actively working to optimize the deployment of BESS projects by leveraging its corporate-academic partnership with the Toronto Metropolitan University CUE. With this partnership, Toronto Hydro and CUE are developing an Optimal Planning Program which optimizes sizing and the return on investment of an ESS for both BTM and FTM applications. This tool will be an essential method in which Toronto Hydro evaluates and deploys BESS projects in the future for applications such as load displacement, deferred system expansion and premium reliability service. Quantifying net benefits for each of these scenarios will allow Toronto Hydro to design storage systems that can maximize the value proposition to the customer and the utility.

Another part of the BESS strategy is to improve asset integration so that newly deployed systems can co-exist with Toronto Hydro's IT framework. This will involve continuing to integrate all existing storage platforms within the Distribution Grid Operations Energy Centre DERMS platform.

E7.2.2.2 Outcomes and Measures

Table 11: Outcomes & Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer service objectives by enabling customer investments in renewable energy and reducing energy costs.

[10] Seguin, R., Woyak, J., Costyk, D., Hambrick, J., & Mather, B. (2016). (tech.). High-Penetration PV Integration Handbook for Distribution Engineers (pp. 4–26). Oak Ridge, Tennessee: Office of Scientific and Technical Information.

Operational Effectiveness - Reliability	• Contributes to service reliability by utilizing BESS technology to improve load-balancing on feeders that have been identified to have issues with respect to MLGR.
Financial Performance	• Contributes to Toronto Hydro's financial objectives and performance by cost-effectively enabling renewable generation where applicable.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy objectives by enabling the proliferation of energy storage, renewable DERs, and grid-modernization.

E7.2.2.3 Drivers and Need

Table 12: Segment Driver

Trigger Drivers	Capacity
Secondary Driver	Reliability, Public Policy

Renewable Enabling BESS

Policy, economic conditions and the preferences of customers and consumers, have facilitated a growing interest in DERs within Toronto Hydro's service territory. This trend is expected to continue into the foreseeable future supported by a number of drivers that are stemming from global, national and local levels such as the Federal Government's green energy tax credit and the recent Regulatory policy changes. In 2022, the Ontario Energy Board enacted changes that enabled third-party ownership of Net Metered generation facilities. Toronto Hydro anticipates that third-party installations will play a key role in driving renewable energy generation ("REG") growth during the next rate period as it did in other provinces and the US where this arrangement is already well established. In addition, the anticipated decreasing costs of photovoltaic panels is expected to have a positive impact on customer interest in REG. These drivers will increase interest in distributed renewable generation projects within Toronto Hydro's service territory by 2029, as shown below on Figure 3. Please refer to the Generation Connections narrative for more details on the drivers behind the anticipated REG growth in the next rate period.

An increase in renewable generation projects will lead to a fundamental change in the power flow conditions at the distribution system and how they need to be managed. This has challenged the conventional radial nature of the grid to accommodate bi-directional power flow. Large scale deployment of REG is known to cause issues in distribution system planning and operations such as unintentional islanding and overvoltage on feeders. As a result, Toronto Hydro must proactively relieve certain grid constraints on feeders in order to accommodate future REG growth.

As part of its DER connection process, Toronto Hydro offers a pre-application report for its customers, providing information about the proposed point of interconnection so the customer can determine if a DER system installation is worth pursuing. The pre-application process also allows Toronto Hydro to discover potential distribution system issues that must be addressed to accommodate the proposed DER. In such instances, Toronto Hydro would work with the customer to find the best solution to move the DER installation forward, such as modifying the proposed system to satisfy the pre-application screening. Although Toronto Hydro has been able to manage DER customer expectations to date through this pre-application process, certain parts of the distribution system are approaching their technical limits and the problem could worsen over the next few years. Renewable Enabling ESS investments can help Toronto Hydro alleviate these issues to accommodate future REG growth, while maintaining adherence to the Transmission Interconnection Requirements.

As can be seen in the Figure 3 below, there has been a consistent increase in the number of renewable generation connections to the distribution grid. The data observed assumes a negligible uptake of wind or other inverter-based DER technologies and therefore uses the solar PV forecast as the primary REG type driving increased penetration. These assumptions are based on historical consumer behaviour in REG adoption in the City of Toronto and are consistent with forecasting models used in the Generation Connections segment.

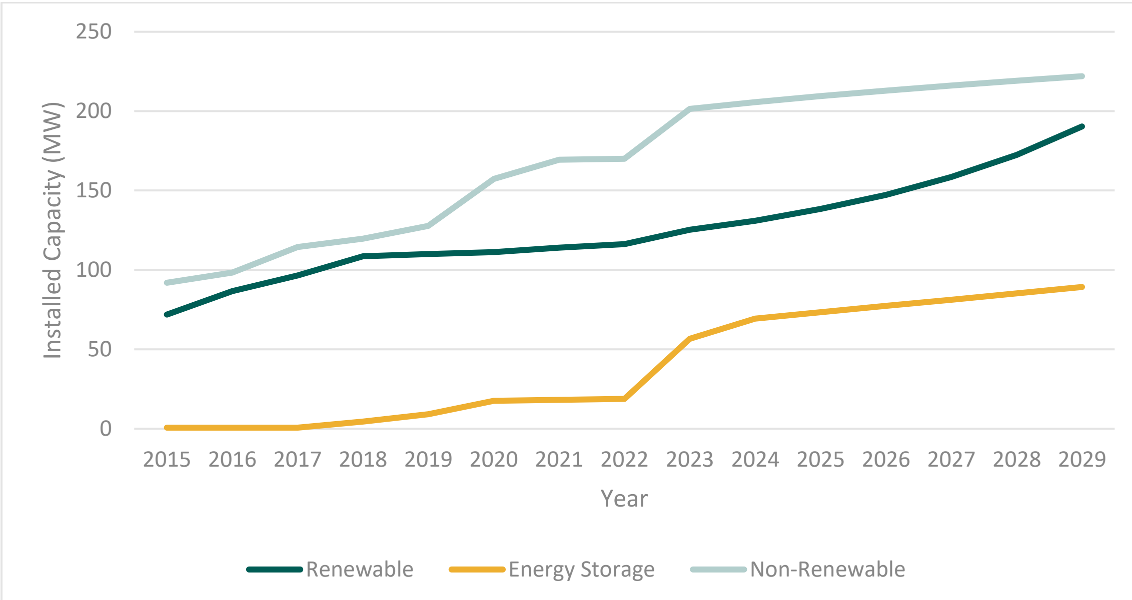

Figure 3: Historical and Forecasted Renewable Generation (MW)

Table 13: Forecast Generation Capacity (in MW)

Generation Type	2023	2024	2025	2026	2027	2028	2029
Renewable	126.4	133.4	143.4	155.1	168.5	183.6	200.4
Energy Storage	56.6	60.0	73.4	77.4	81.4	85.4	89.5
Non- Renewable	198.2	212.1	215.6	218.7	221.6	224.3	226.8
Total	**381.2**	**405.5**	**432.4**	**451.2**	**471.5**	**493.3**	**516.7**

High penetration of renewable energy generation sources can lead to grid instability if not managed appropriately. Two modes of grid instability can be seen: unintentional islanding and system overvoltage. While these issues can not be resolved easily using conventional utility approaches, ESS solutions present an ideal alternative given their ability to dynamically charge and discharge to balance feeder loading. The following sections will outline the two modes of grid instability and expand on how ESS can help alleviate the issues.

Unintentional Islanding

In the past few years, there have been numerous studies, standards and guidelines with respect to DER integration, such as IEEE Standard P1547.2/D6.5, August 2023 (Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces)[11] and National Renewable Energy Laboratory's High Penetration PV Integration Handbook for Distribution Engineers (NREL Handbook). These documents prescribe limitations on DER aggregate capacity to be less than one-third of the minimum load of the Local Electric Power System. [12] As the ratio of generation capacity to minimum load increases, the amount of time required by inverters to respond to anti-islanding scenarios increases and this can adversely impact the effective inverter response to anti-islanding scenarios. This scenario can be mitigated with the addition of transfer trip protection, which is only a requirement for DER connections over 1MW; however, this is a costly measure. Furthermore, for feeders that have a high penetration of small to medium DER connections, it would not be economically feasible for each customer to install transfer trip as the cost is too high relative to the cost of the connection. Since most of the REG connections that get connected to Toronto Hydro's grid are small to medium size connections, renewable enabling ESS becomes an attractive option as it can serve to mitigate this risk for any customer along the feeder as opposed to being an individual customer solution.

Toronto Hydro conducted an analysis for all feeders in its system to establish minimum load to generation ratios[13] in accordance with the applicable guidance found in IEEE-P1547.2/D6.5, August 2023. The methodology consisted of aggregating the DER generation capacity at the feeder level. For this particular study only the DERs that were connected and in-service were used, and DERs that were proposed were only factored into the forecasted values. The next step involved using load profiles to determine the minimum load on each feeder in the past three years and computing the MLGR. This process was repeated for all feeders that had aggregate DER capacity above 500 kW. The list was further refined by calculating the REG penetration ratio on each feeder which helps identify feeders that would best be served by a renewable enabling ESS solution.

The DER forecast shown in Figure 3 above is a system level forecast that is consistent with the GPMC and Customer Connections narratives. This system level forecast was applied to the feeder level

[11] "IEEE Draft Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE P1547.2/D6.5, August 2023 , vol., no., pp.1-322, (11 Aug. 2023).
[12] Ibid.
[13] Determined as available utility fault current divided by DG fault contribution in affected area.

forecast in Table 14 below to determine the DER forecast for each of the shortlisted feeders as well as the forecasted impact on MLGR.

The study found that 23 feeders currently exceed the 3:1 minimum load to generation screening ratio outlined by the NREL Handbook and is shown in Table 14 below. Assuming there are no short circuit capacity constraints at the transformer station and given the forecasted growth in REG only by 2029, an additional 24 feeders would exceed the generation to minimum load ratio.

Table 14: MLGR feeder analysis

Station	Feeder Name	Nameplate Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Minimum Load (MW)	Current MLGR	MLGR Forecast 2029	REG Connections enabled (MW)
Agincourt TS	63-M6	3.530	100.0%	5.77	7.10	2.011	1.230	2.24
Finch TS	55-M31	1.750	100.0%	2.95	3.52	2.011	1.193	1.20
Fairbank TS	35-M8	1.997	83.0%	2.80	5.50	2.753	1.750	1.15
Rexdale TS	R29-M1	1.115	100.0%	1.94	2.54	2.275	1.305	0.83
Horner TS	R30-M3	0.760	100.0%	1.38	1.91	2.519	1.387	0.62
Scarborough TS	E5-M24	3.712	16.5%	1.15	4.12	1.109	0.969	0.53
Horner TS	R30-M10	4.573	12.5%	1.08	5.12	1.120	1.007	0.51
Bathurst TS	85-M6	6.761	7.5%	0.98	5.56	0.822	0.768	0.47
Bathurst TS	85-M30	5.250	9.5%	0.97	2.83	0.539	0.495	0.47
Finch TS	55-M32	1.508	33.2%	0.97	4.09	2.712	2.069	0.47
Leslie TS	51-M25	1.677	25.5%	0.85	4.88	2.911	2.322	0.43
Finch TS	55-M29	1.914	21.7%	0.83	4.22	2.205	1.809	0.42
Fairchild TS	80-M10	1.300	23.1%	0.65	2.69	2.069	1.629	0.35
Leslie TS	51-M23	2.100	14.3%	0.65	4.58	2.181	1.868	0.35
Bathurst TS	85-M7	6.105	1.7%	0.34	2.62	0.429	0.413	0.24
Bathurst TS	85-M1	6.013	0.2%	0.20	6.86	1.141	1.107	0.18
Finch TS	55-M2	5.300	0.0%	0.18	2.96	0.558	0.541	0.18
Bathurst TS	85-M32	4.750	0.0%	0.18	6.08	1.280	1.234	0.18
Windsor TS	A-61-WR	1.500	0.0%	0.18	2.75	1.835	1.642	0.18
Esplanade TS	A-39-X	7.000	0.0%	0.18	14.50	2.072	2.021	0.18
George Duke TS	A-45-GD	1.050	0.0%	0.18	2.18	2.074	1.776	0.18
Fairchild TS	80-M23	0.900	0.0%	0.18	2.12	2.356	1.970	0.18
Cecil TS	A-41-CE	1.275	0.0%	0.18	3.37	2.646	2.326	0.18

Renewable Enabling ESS can be deployed on such feeders in order to increase the minimum load to generation ratio to the recommended threshold. The technology has the capability to do so by functioning like a load when the minimum load is low. Conversely, when the minimum load is appropriately above the threshold, the ESS can act like a generator by supplying energy. This can provide FTM load displacement as well as other target area specific benefits.

In short, the screening ratios show that by 2029 all 47 feeders will have a high penetration of PV generation and require grid investments or other solutions to ensure the safety of the grid and allow further REG connections. ESS is recognized as an effective distribution system solution to increase the PV connection capacity. [14]

The direct benefit of installing renewable enabling ESS can be quantified by the amount of REG capacity that is enabled through these investments which is shown on the far-right column in Table 14 above. This also forms the basis for prioritizing which feeders should be resolved as they provide the largest benefits as a renewable enabling investment. Otherwise, a lack of these renewable enabling ESS investments would result in a forecasted amount of 30MW of REG by 2029 to be potentially rejected for connection.

Toronto Hydro also envisions renewable enabling ESS investments that are driven by large customers installing large renewable DERs. Such a large and sharp increase of renewable DER penetration could disturb the grid stability and the generation to load ratio. Renewable enabling ESS solutions would be installed on the relevant feeders to support the grid, smooth the ratio and allow for the increase of renewable generation on the grid.

System Overvoltage

ESS deployments can also mitigate the grid risk of experiencing overvoltage on some of Toronto Hydro's feeders. Load demand and PV generation have different impacts on a feeder's voltage profile. As load demand increases, operating voltage dips, while as PV generations increases, the voltage spikes. Based on internal studies, there is an increased overvoltage risk for equipment on feeders with low load demand and a high PV penetration. Results have shown that utilizing a BESS to balance the load on such feeders could mitigate that risk and consequently enable further renewable connections on the grid.

[14] For example, see:
(i) J. Seuss, M. J. Reno, et al, "Improving distribution network PV hosting capacity via smart inverter reactive power support", Proc. IEEE PES General Meeting, July 2015, pp. 1–5.
(ii) Z. Waclawek, et al, "Sizing of photovoltaic power and storage system for optimized hosting capacity", Proc. IEEE International Conference on Environment and Electrical Engineering, June 2016, pp. 1–5.
(iii) B. P. Bhattarai, et al, "Overvoltage mitigation using coordinated control of demand response and grid-tied photovoltaics", Proc. IEEE SusTech, Jul 2015.
(iv) F. Capitanescu, et al, "Assessing the potential of network reconfiguration to improve distributed generation hosting capacity in active distribution systems", IEEE Transactions on Power Systems, Jan 2015, vol. 30, no. 1, pp. 346–356.
(v) Y. Takenobu, et al, "Maximizing hosting capacity of distributed generation by network reconfiguration in distribution system", Proc. Power Systems Computation Conference (PSCC), June 2016, pp. 1–7.

E7.2.2.4 Expenditure Plan

1. 2020-2024 CIR Energy Storage Systems ("ESS") Program

Table 15: 2020-2024 CIR – ESS Program ($ Millions)

	2020	2021	2022	2023	2024	Total
GPESS	-	2.7	2.8	-	-	5.5
REBESS	1.0	1.0	1.0	1.0	1.0	5.0

Table 16: Actual and Bridge Costs – ESS Investments ($ Millions)

	Actual			Bridge	
	2020	2021	2022	2023	2024
BESS[15]	-	0.5	0.1	0.3	0.3

Toronto Hydro planned to install aggregate capacity of 8MW/4MWh of Grid Performance ESS over the 2020-2024 period, at a total cost $5.5 million. The plan was for the project to be implemented in 2021 and 2022. Toronto Hydro also proposed in the last rate application to install three Renewable Enabling ESS units with an aggregate capacity of 2.35MW/9.5MWh, at a total cost of $5 million.

Toronto Hydro faced numerous challenges in completing the proposed projects and was unable to proceed as planned. After exploring additional opportunities to deploy ESS, Toronto Hydro is proceeding with one renewable enabling ESS unit in the current rate period. This process has provided valuable information and experience that has informed the development of Toronto Hydro's ESS plan going forward. Toronto Hydro is revising its approach for this program in the 2025-2029 period, focusing on creating a more scalable, demand-driven ESS program that utilizes small-scale ESS technologies.

Toronto Hydro faced three significant challenges in deploying ESS in the 2020-2024 rate period:

i) Siting projects;
ii) Supply chain constraints; and
iii) Integration of one-off procurements into Toronto Hydro's IT and other systems.

[15] BESS amounts reflect combined investments for GPESS and REBESS.

Building on the lessons learned from navigating these challenges, Toronto Hydro has identified an opportunity to deploy an ESS unit to target a feeder that exceeds the MLGR threshold.

Challenges Deploying ESS

<u>Siting ESS Projects</u>

Finding a site has been the one of the biggest roadblocks for installing ESS in Toronto. It is often difficult to line-up a site in an area where ESS can provide cost-effective grid services. This challenge is uniquely difficult for Toronto Hydro as its service area is dense and urban. So far, Toronto Hydro has installed one front-of-the-meter ESS (Bulwer) at a decommissioned Municipal Station site.

<u>Supply Chain Constraints</u>

During the current rate period, COVID-19 led to significant supply chain issues resulting in major delays throughout the entire ESS sector. Certain types of equipment, such as Static Transfer Switches (STSs) had lead times of up to 2 years. Many of the after effects of these supply chain issues continue to impact project execution, specifically with respect to shortages in lithium production for Lithium Ion ESSs. Supply chain risks have diminished since the height of COVD-19 and are not expected to be material over the next rate period.

<u>Integration of One-off Procurements</u>

Another challenge relates to the integration of ESS into existing frameworks and systems. This is exacerbated by one-off procurements with several different vendors. For example, it has been a challenge to integrate various types of custom BESS systems that utilize different software platforms for system charging and management from an IT perspective. Toronto Hydro's IT systems have strict requirements with respect to data access, hardware and security. It is also necessary to create maintenance plans for the ongoing management of these assets, which can be made complicated when there are various types of custom system installed. To that end, Toronto Hydro is currently working on standardizing the process of ESS design and procurement through the development of technical requirements that will be used in future RFPs.

Grid Performance ESS (GPESS) Project

As part of the 2020-2024 period, Toronto Hydro explored the possibility of installing a 5 MW ESS to mitigate voltage sags on feeder 51-M30, which is fed by Leslie TS. This project was intended to pilot the use of an ESS to resolve voltage sag issues for large commercial customers located on the targeted feeder. This feeder was selected based on analysis evaluating the following criteria:

- Number of customers impacted:
  - More than one key account customer connected on the feeder
- Land for ESS installation:
  - Feeder must be in proximity to existing decommissioned Municipal Stations (MS) that can be utilized for ESS site
- High number of sags:
  - ION meter data for key account customers on select feeders exhibited high number of sags recorded for the 2018 to mid 2021 period
  - The number of interactions regarding voltage sag concerns between the customer and the Key Account team at Toronto Hydro were also considered a factor

Table 17: Targeted Feeder for GPESS Deployment

Candidate Feeder	Decommissioned MS Nearby?	# of Key Customers	2021 Recorded Sag Event	Recommended GPESS Size
51-M30	Yes (Lesmill MS)	2	Key Customer #1 - 32 Key Customer #2 - 29	5.2MW/1.3MWh

In 2020, Toronto Hydro hired Quasar to perform a study about the technical feasibility of an energy storage system that eliminates short duration voltage fluctuations on a feeder. The final report provided a high-level cost estimate for the feasible options, identified completed projects in which the solutions have been implemented and developed a list of vendors that offer the required equipment to implement suggested solutions.

In 2021, Toronto Hydro worked with GE to determine the feasibility of integrating a power conditioning system within the distribution system. The aim of the study was to identify the main possible topologies, determine load case scenarios, simulate the performance of the best selected topology and develop a preliminary sizing of required components.

In 2022, Toronto Hydro developed and ran a Request-for-Proposals (“RFP”) process to procure an ESS capable of providing voltage support on the identified feeder, as well as peak-shaving support, and the ability to island for the purpose of outage mitigation. This RFP was put out to market twice:

once in July 2022 and once in September 2022. Both processes resulted in no appropriate bids from vendors.

To understand the lack of response from vendors, Toronto Hydro conducted feedback sessions and learned that many BESS developers were focusing on larger-scale deployments (greater than 10 MW) that enabled ownership retention and power purchase agreements with the IESO (via medium and long-term contracts). Other vendors noted that the technical requirements of Toronto Hydro's RFP were complex and necessitated more in-depth preliminary engineering analysis to accurately define the requirements. With these lessons learned, Toronto Hydro is working with external consultants to undertake engineering studies assessing the technical feasibility of a BESS that addresses feeder-level voltage sags, while also determining the compatibility of this use case with others (e.g. peak-shaving, load-balancing, black-start). The goal is to be better equipped to scope BESS projects that enable benefit stacking, maximizing the cost-effectiveness of these projects.

Renewable Enablement ESS Project

Despite the previously-described difficulty in finding a viable site for REBESS, Toronto Hydro aims to target one small deployment within this rate period. The deployment being targeted this rate period will be on one of the 23 feeders which are above the MLGR threshold as highlighted in Table 14 above. The feeder selected for the deployment will hinge on the various constraints such as location, sizing and budget. The prudent approach would be to target a singular small deployment in an area that is relatively easy to deploy, gather learning lessons and carry those lessons into the planned deployments for the next rate period.

In addition to this, Toronto Hydro is working with internal stakeholders and vendors to explore innovative methods of deployment such as smaller scale BESS units along the right of way in order to alleviate the need to find large land areas as well as available decommissioned Municipal Stations that can be repurposed to site BESS.

2025- 2029 Forecast Expenditures

Table 18: 2025-2029 CIR – BESS ($ Millions)

	2025	2026	2027	2028	2029	Total
BESS	3.6	3.6	7.5	3.8	4	22.5

Table 19: 2025-2029 CIR – BESS (Systems)

	2025	2026	2027	2028	2029	Total
BESS	1	2	2	2	2	9

Toronto Hydro plans to deploy nine projects in the BESS program with an aggregate capacity of 10.2 MW to mitigate the forecasted impact of PV penetration and enable further renewable growth on the grid. The 10.2 MW of BESS capacity is what is needed to bring up the MLGR ratio on the 9 high-priority feeders outlined in Table 14, to the required MLGR threshold. The planned deployments are estimated to cost $22.5 million with an assumption of $446/kWh This works out to $1.78M/MW for a four hours system and results in an expenditure cost of $18.19 million. A 10 percent buffer was added for potential cost overruns resulting in a $20 million total expenditure cost. The derived $/MW is based on industry benchmark[16] as well as Toronto Hydro's renewable enabling ESS technology evaluation. Toronto Hydro plans to distribute the planned numbers of projects evenly over the next rate period to optimize utilization of current staff and take advantage of one project's lessons learned onto the next one.

Renewable enabling BESS investments are distribution investments that support the growth of distributed renewable generation on the system, that in turn offset generation and transmission investments to the benefit of all Ontario rate payers, and that also create environmental benefits. As with other renewable enabling improvements, renewable enabling BESS are funded six percent in Toronto Hydro's rate base and 94 percent through the provincial renewable enabling improvement revenue stream. Over the 2025-2029 period, $22.5 million is proposed for this segment, $1.6 million (six percent) allocated to Toronto Hydro's rate base as the assets are in-service. These investments are expected to enable the aggregate connection of 10.2 MW of REG by 2029, which wold otherwise not be possible due to the technical limitations of the grid.

[16] Viswanathan, Vilayanur, et al. "Energy Storage Cost and Performance Database." *Pacific Northwest National Laboratory*, 1 Aug. 2022, www.pnnl.gov/lithium-ion-battery-lfp-and-nmc.

Table 20: Priority REBESS Deployments

Station	Feeder Name	Existing DER Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Minimum Load (MW)	Current MLGR	MLGR Forecast (2029)	REG connections enabled by 2029 (MW)	Req. BESS Size (MW)
Agincourt TS	63-M6	3.53	100.0%	5.77	7.10	2.011	1.230	2.24	3.49
Finch TS	55-M31	1.75	100.0%	2.95	3.52	2.011	1.193	1.20	1.73
Fairbank TS	35-M8	2.00	83.0%	2.80	5.50	2.753	1.750	1.15	0.49
Rexdale TS	R29-M1	1.12	100.0%	1.94	2.54	2.275	1.305	0.83	0.81
Horner TS	R30-M3	0.76	100.0%	1.38	1.91	2.519	1.387	0.62	0.37
Finch TS	55-M32	1.51	33.2%	0.97	4.09	2.712	2.069	0.47	0.43
Leslie TS	51-M25	1.68	25.5%	0.85	4.88	2.911	2.322	0.43	0.15
Finch TS	55-M29	1.91	21.7%	0.84	4.22	2.205	1.809	0.42	1.52
Fairchild TS	80-M10	1.30	23.1%	0.65	2.69	2.069	1.629	0.35	1.21
Total				**16.57**				**6.12**	**10.2**

E7.2.2.5 Options Analysis

1. Option 1: Do Nothing

Twenty-three feeders in Toronto Hydro's territory currently exceed the acceptable generation to minimum load ratios and an additional 24 feeders are forecasted to exceed acceptable ratios by 2029. If no action is taken, it is possible that forecast demand for DG, including REG, would not be safely accommodated in those areas. This could potentially put forecasted REG connections with an aggregate capacity of 29.78MW at risk of getting rejected by 2029. This would be an undesirable outcome for customers, the City of Toronto, and Toronto Hydro and would hinder Toronto Hydro's ability to meet its obligation to connect renewable generation (i.e. pursuant to Section 6.2.4 of the Distribution System Code). This will also restrain the efforts being made to accelerate the uptake of renewables and meet net zero targets in Toronto. Customers who are willing to invest in modernizing the grid will likely become frustrated, and the associated grid and upstream benefits will not be realized. Finally, this will be in non-compliance with the results of Toronto Hydro's customer engagement process, which stressed on the importance of allocating expenditures to modernize the grid and support renewable growth.

2. Option 2: Traditional "poles and wires" solutions

While Toronto Hydro has the Generation Protection Monitoring & Control (GPMC) program to address system-wide issues to enable DER, issues involving generation to minimum load ratio, feeder phase imbalances and bus voltage imbalances will still persist and could potentially inhibit the connection of new renewable DER projects. GPMC will give Toronto Hydro the required control to disconnect DERs in case of an unintended islanding situation. However, the issues explained in section E7.2.2.4 cannot be addressed with the GPMC initiatives.

Feeder re-configurations and reverse load transfers could be performed to increase load on forecasted feeders where generation to minimum load ratios are high. However, this method may decrease reliability and may not always be feasible due to the existing network configuration. Furthermore, these are static solutions not well-suited to managing the dynamic nature of balancing load to generation, meaning these options would not resolve the issue the way a BESS would.

Another traditional option to mitigate the risk of unintentional islanding is with the addition of transfer trip protection; however, this is only a requirement for DER connections over 1MW and is a costly measure. Since most of the REG connections that get connected to Toronto Hydro's grid are small to medium size connections, it would not be feasible for customers to install transfer trip as the cost is too high relative to the cost of the connection.

3. Option 3: Production Curtailment and Decreasing Operational Margin

With better resource monitoring, and forecasting and real-time estimation of the grid capacity, applicable operational margins can be reduced. This in turns allows the existing infrastructure to be used more efficiently and to a greater extent (i.e. with a higher capacity factor). For more detailed information regarding this option, please refer to the Generation Protection, Monitoring, and Control Program.[17]

Curtailment occurs when plants are required to reduce their generation output in order to maintain the operational limits of the grid. This may entail a small gradual decrease of the production (referred to as soft curtailment) or a complete stop to production through measures such as inter-tripping (referred to as hard curtailment). Soft curtailment requires a communication infrastructure and methods to assess the real-time performance of the grid and the appropriate production decrease.

[17] Exhibit 2B, Section E5.5.

In a deregulated market without vertically integrated utilities, it requires willingness from grid users to participate and a legal framework enabling such participation. Moreover, economic arrangements are required to allocate the loss of income stemming from curtailed production.

It is also important to note that for renewable enablement, curtailment is not an option as REG is either connected or not. While curtailment is not viewed as a viable option at the moment, Toronto Hydro is assessing the feasibility of having flexible DER connections on its system, which could work to mitigate load-to-generation imbalances for further DERs. More information about this program is outlined in the Grid Modernization Roadmap narrative.

4. Option 4 (Selected Option): Proposed Solution

The proposed Renewable Enabling BESS program will provide Toronto Hydro with strategic capabilities to address specific issues relating to REG enablement in targeted areas of its distribution system. It will allow Toronto Hydro to mitigate the problems described in Section 7.2.2.4 and fulfill its regulatory obligations to connect REG projects pursuant to the DSC. The proposed solution also best positions Toronto Hydro to support the goals of the Climate Action Plan with respect to enabling renewable generation and deploying energy storage. It is expected that these investments will enable the aggregate connection of 10.2 MW of REG by 2029 which would otherwise be constrained. The overall cost of this option is an estimated $20 million over the 2025 to 2029 period.

E7.2.3 Execution Risks and Mitigation

Project execution risks may impact project design, project siting, approvals, construction, project schedule and commissioning. Compared to traditional technologies, there are fewer technical resources in the sector with knowledge on ESS that are available to design, install and commission the systems, which can lead to a delay in program implementation and increased costs. Toronto Hydro will manage this risk by researching and applying relevant experiences from other jurisdictions and investing in training and staff development for engineering and skilled trades.

ESS projects are complex due to bi-directional power flow and interface protections between project locations and their associated feeder or station supply point. Commissioning risk can be mitigated by using a standard requirements matrix and site acceptance testing protocol. Further, in-depth training in advance of actual field work is planned for crew members and operations staff who will take part in ESS installation and commissioning.

Toronto Hydro will manage risks regarding integrating BESS with our current IT network through consciously working with the IT team to understand their technical requirements and considerations. This will help establish a standardized IT framework for the BESS program that we can incorporate in our upcoming project RFPs.

As outlined in earlier sections of this document, Toronto Hydro anticipates project siting to be one of the critical risks for this program in the next rate period. In order to manage this risk in the short term, Toronto Hydro is working with its Stations and Facilities teams to explore any available opportunity to repurpose existing Toronto Hydro facilities such as decommissioned Municipal Stations. At the same time, the end goal is to establish a more standardized and reliable approach for project siting. Toronto Hydro's vision is to create a strategy that leans on modular and small-scale BESS to enable BESS deployments on city boulevards, similar to other traditional Toronto Hydro assets.

Project schedule risk can be effectively managed by dedicated project teams that provide short-interval control and regular coordination between the utility and customers. Toronto Hydro will dedicate its efforts to ensure labour availability and manage project prioritization with other capital project and planned maintenance work will be managed to implement this program on-schedule.

Construction cost variance is mitigated through a competitive procurement system for ESS projects and standard contract provisions which provide fixed price responsibility and liquidated damages for non-performance. Based on the 2022 Grid Energy Storage Technology Cost and Performance Assessment by Pacific Northwest National Laboratory,[18] battery ESS technology will mature and prices will fall, providing some protection against year-over-year inflation and a degree of budget contingency. Battery costs represent approximately half the cost of ESS, while inverters, switchgear, transformation, controls, conditioning, civil work and enclosures make up the balance. Further, the report determined that current installed costs for Lithium Ion (LFP) BESS is $446/kWh and this is expected to decrease to $340/kWh by 2030. As such, over the 2025-2029 period, the cost/benefit value proposition of ESS will likely continue to improve, thereby facilitating increased use of this solution to address customer needs.

[18] Viswanathan, Vilayanur, et al. "2022 Grid Energy Storage Cost and Performance Assessment." *Pacific Northwest National Laboratory*, Aug. 2022.

E7.4 Stations Expansion

E7.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 139.9	**2025-2029 Cost ($M):** 121.9 /C
Segments: Downsview TS, Hydro One Contributions[1]	
Trigger Driver: Capacity Constraints	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Public Policy Responsiveness, Environment	

Toronto Hydro's Stations Expansion program (the "Program") addresses medium to long-term system capacity needs. The Program is driven by capacity constraints at the station or regional level, which can no longer be effectively managed by the Load Demand program alone. Increased and continued densification, population growth, and electrification are driving the need to relieve the station loading and create additional capacity. If not addressed proactively, this will impact Toronto Hydro's ability to connect customers to its distribution system, and expose Toronto Hydro's stations to risk during peak loading periods. The primary focus of the work planned in the 2025-2029 rate period is on the horseshoe northwest and horseshoe east regions of the distribution system, where constraints currently exist or are forecasted to materialize with growth.

The Stations Expansion program consists of the two segments summarized below, and is a continuation of the expansion activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[1]

- **Downsview TS**: This segment aims to expand station capacity by constructing a new transformer station ("TS") in the Downsview area of Toronto, with a capacity of 174 MW. Additional capacity is needed to support forecasted growth and development in the City's Downsview area, while relieving the highly-loaded Bathurst and Finch TSs. A demand study of the Downsview area has forecasted a load demand of 195 MW by 2035.[2] The construction of a new TS is a large project requiring a long lead time. In order to be ready to meet the forecasted demand, Toronto Hydro must start planning and preparing for this project in the

[1] EB-2018-0165, Exhibit 2B, Section E7.4
[2] Downsview Area Secondary Plan – Electricity Demand Justification Report by DMP Energy (Aug 08 2022)

2025-2029 rate period for an anticipated energization date of late 2033. This planning and preparation stage will include preparatory capital investments such as: property acquisition, property site preparation construction of a new station building, high voltage circuit breakers and bus work, and partial construction or payments towards station assets.[3] Toronto Hydro forecasts to spend $70.2 million in this stage. Once planning and preparation is complete, Toronto Hydro will move into the construction and energization stage, which will include the installation of the remaining electrical assets, the installation of station ancillary assets, and the commissioning and energization of all electrical assets. Toronto Hydro forecasts to spend $70.0 million during the commissioning and energization stage post-2029.

- **Hydro One Contributions:** this segment covers Toronto Hydro's forecasted capital contributions to Hydro One for work related to:
  - Downsview SS: A new Hydro One switching station to provide Toronto Hydro's new Downsview TS access to Hydro One's transmission network;
  - Sheppard TS New Switchgear: A new switchgear to provide access to existing idle capacity at the existing Sheppard TS and enable new Distributed Energy Resources (DER) connections [E3.3 Capacity and Constraints to Connect DER]; /C
  - Manby TS T13/T14 DESN Upgrade: An upgrade to the transformers at this DESN during their natural end-of-life (EOL) renewal and an expansion of the switchyard to accommodate new feeders, to facilitate future load growth at this highly loaded station; and
  - Cost-effective capacity upgrades of EOL Hydro One-owned power transformers, as anticipated based on the IRRP process and latest Planning work in 2022.[4]

  Toronto Hydro plans to invest an estimated $51.7 million in this segment in the 2025-2029 rate period compared to a forecasted $60.4 million in 2020-2024. /C

The investments summarized above for Hydro One transformer replacement are informed by the recent Regional Infrastructure Plan ("RIP") and 2020 Integrated Regional Resource Plan ("IRRP") activities conducted in coordination with Hydro One. The most recent planning document from this process is the 2022 Needs Assessment Report for the Toronto Region ("Needs Assessment"). A

[3] Site preparation will include items such as, but not limited to, the clearing of land, construction of a ground grid, installation of crushed stone, and a station fence.
[4] Hydro One Needs Assessment Report, Toronto Region, Dec 2022

reconciliation of the Needs Assessment with Toronto Hydro's Stations Expansion program is found in Section E7.4.7 Regional Planning Needs of this narrative.

The Stations Expansion program also responds to the need to maintain system reliability and increase grid resiliency to support Ontario public policy drivers. To this end, the Program focuses on Toronto Hydro's broad strategy of grid modernization within the context of an aging, dense urban infrastructure, aiming to support customers and load growth and both mitigating and adapting to climate change through grid resiliency and innovation.

In total, Toronto Hydro plans to invest $121.9 million in the Stations Expansion Program in 2025-2029, compared to a forecasted $139.9 million in 2020-2024. Toronto Hydro expects to add 321 MW of new capacity to its system from projects completed by 2029, and start projects that will contribute to an additional 174 MW of capacity when completed in 2030-2034.[5] /C /C

E7.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Reducing the number of stations unable to connect new large customers in the downtown and Horseshoe areas by investing in 321 MW in additional supply capacity by 2029; ○ Alleviating feeder position limitations that prevent customer connections; and ○ Enabling new DER connections by providing increased short-circuit capacity with new DESNs.
Operational Effectiveness - Reliability	• Contributes to maintaining Toronto Hydro's system capacity and reliability objectives by: ○ Providing redundancy and operational flexibility by upgrading capacity at supply points to keep the number of highly loaded stations (with loads > 90 percent capacity) at a minimum for the downtown and Horseshoe areas;

[5] The Downsview TS will contribute 174 MW of new capacity and is forecasted to come in-service during the 2030-2034 rate period. /C

Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy objectives by: ○ Supporting the provincial long-term energy planning and IRRP by meeting local needs; and ○ Enabling electrification by investing in additional capacity and operational flexibility.
Environment	• Contributes to Toronto Hydro's environmental objectives by investing in capacity to support operational flexibility, enable electrification.

E7.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Capacity Constraints
Secondary Driver(s)	Reliability, DER Connections

The Stations Expansion program is driven by constraints at the station or regional level, which can no longer be effectively managed by the Load Demand program alone. Over the next decade, Toronto Hydro's distribution system is expected to face many new challenges and demands due to population growth, densification, and electrification. These factors will ultimately result in increased capacity constraints at its stations, creating the need to relieve constraints by building additional capacity.

Because these challenges, particularly the acceleration of electrification, are subject to many factors outside of Toronto Hydro's control, such as government policies and consumer preferences, the timing for when capacity constraints will materialize is uncertain. Toronto Hydro has managed this uncertainty by considering multiple inputs to develop a plan that will satisfy its capacity needs, in a least-regrets investment approach. These inputs are as follows.

- **Load Forecasts:** Toronto Hydro's 10-Year Peak Demand Forecast (see Section D4 of the Distribution System Plan), and Hydro One's Needs Assessment Report 10-Year Load Forecast /C
- **City of Toronto Development Plans:**[6] Downsview Area Secondary Plan, East Harbour Development, Golden Mile Secondary Plan, and Scarborough Centre Secondary Plan

[6] City of Toronto, Secondary Plan Key Map (November 2015) https://www.toronto.ca/wp-content/uploads/2017/11/980a-cp-official-plan-Map-35_SecondaryPlans_AODA.pdf

- **Future Energy Scenarios ("FES"):**[7] Six scenario-based outlooks to assess impacts to station loading due to: the electrification of heating and transportation, building stock growth, and DER integration.

From this analysis, Toronto Hydro identified that the City of Toronto Development Plans will be a primary driver of forecasted load growth in both the Downtown and the Horseshoe areas. In particular, Toronto Hydro expects that this growth will add constraints to Fairbank TS and Finch TS within 10 years, and at Bathurst TS within 15 years. Due to the long lead time needed to implement a lasting solution for these stations, Toronto Hydro must begin making necessary investments in the 2025-2029 rate period. /C

A second key driver of forecasted load growth identified is electrification, which is forecasted to impact Toronto Hydro's system more broadly than the Secondary Plans which target specific areas. This is driving a need for capacity to be made available throughout Toronto Hydro's system, to ensure that Toronto Hydro's system does not become a barrier to new customers looking to access its system, regardless of where those customers may materialize.

The lack of capacity at Toronto Hydro's stations results in two negative consequences. First, it negatively impacts customer connections by preventing new customers from connecting to the grid or burdening connecting customers with higher connection costs. Second, it reduces the reliability of the station, and may result in load shedding.[8]

When a customer submits a connection request to a station which is highly loaded, Toronto Hydro can either connect the customer to the highly loaded station by first completing a load transfer, or to another station with capacity further away resulting in a higher connection cost. When multiple neighbouring stations are highly loaded, these options become even more limited, and connection costs become even higher.

When station load exceeds capacity, equipment losses result in customer outages during periods of peak loading. As a result, Toronto Hydro or Hydro One is not able to complete maintenance or replacement work during peak periods, which typically results in the deferral of work needed to

[7] Exhibit 2B Section D4 Capacity Planning & Electrification

[8] Load Shedding is the process during which Toronto Hydro temporarily shuts down power supply to a limited number of customers, in order to reduce its station load beneath its station capacity. Power supply is restored to customers when doing so would no longer result in an overload. When needed, load shedding is generally rotated across customers for a few hours each, so that no customers experience long duration outages while others experience no outages at all.

maintain station reliability. To otherwise complete the work during peak periods would result in a shortened life of the existing station assets, which cannot be readily replaced. A lack of station capacity results in reduced reliability at the station, which affects tens of thousands of customers and typically 100-300 MW of customer load per station. Because of the significant consequences in the event of an outage, Toronto Hydro would be required shed load[8] to maintain station load within its capacity.

Hydro One's 2022 Needs Assessment, as part of Regional Planning identifies station capacity needs at: Bathurst and Finch TSs, Basin TS, Fairbank TS, Glengrove TS, Sheppard TS, Strachan TS, and Warden TS. The Report also recommends incremental capacity upgrades at Basin TS, Duplex TS, Manby TS, and Strachan TS during renewal work. Toronto Hydro's analysis has reached similar conclusions; and as a result, the work planned under the Stations Expansion Program is aligned with the NA needs and those in the 2020 Regional Infrastructure Plan ("RIP") report.[9] Table 4 and Table 5 below highlight the needs and how they are addressed through the Stations Expansion program.

The IESO's Integrated Regional Resource Plan ("IRRP")[9] for the Toronto Region is currently underway, and as a result, IRRP needs and recommendations have not been produced at this time. However, Toronto Hydro is presenting the same needs to the Toronto IRRP Working Group as those presented in the Stations Expansion Program.

Table 4: Station Capacity Needs from Needs Assessment and RIP

Station Capacity Need	Needs Assessment Report Timing	Needs Assessment Report Section	RIP Report Section	Stations Expansion Narrative
Bathurst TS / Finch TS	*Beyond 2031*	*7.3.6*	*N/A*	See E7.4.3.2.1
Basin TS	*2030-2035*	*7.3.4*	*7.9.4*	See E7.4.3.2.2
Fairbank TS	*2030-2035*	*7.3.1*	*7.9.1*	Included in 2020-2024 Stations Expansion plan, and in E7.4.3.2.1.
Glengrove TS	*Beyond 2031*	*7.3.5*	*N/A*	Addressed with new capacity at Duplex TS in E7.4.3.2.6
Sheppard TS	*2030-2035*	*7.3.2*	*7.9.2*	See E7.4.3.2.4

[9] Exhibit 2B, Section B, Appendix A, B, C, D, and E

Station Capacity Need	Needs Assessment Report Timing	Needs Assessment Report Section	RIP Report Section	Stations Expansion Narrative
Strachan TS	*2030-2035*	*7.3.3*	*7.9.3*	Addressed through transformer upgrade in E7.4.3.2.6
Warden TS	*Beyond 2031*	*7.3.7*	*N/A*	See E7.4.3.2.3

Table 5: NA Asset Renewal Needs where Upgrade is Recommended in NA and RIP

Asset Renewal Need	Renewal Timing[10]	Needs Assessment Section	RIP Report Section	Stations Expansion Narrative
Basin TS T3/T5 Transformers	*2027*	*7.1.4*	*N/A*	See E7.4.3.2.6
Charles TS T3/T4 Transformers	*2026*	*7.1.2*	*N/A*	
Duplex TS T1/T2 Transformers	*2026*	*7.1.3*	*N/A*	
Duplex TS T3/T4 Transformers	*2031*			
Manby TS T13/T14 Transformers	*2030*	*7.1.9*	*7.6*	
Strachan TS T14 Transformer	*2025*	*7.1.1*	*N/A*	
Strachan TS T13/T15 Transformers	*2031*			
Windsor TS (John TS) T2/T3 and T5/T6 Transformers	*2026*	*N/A*	*7.8*	Included in 2020-2024 Stations Expansion plan.

The station expansion program continuously improves and expands Toronto Hydro's grid in order to align itself with the City's growth and electrification endeavors. The work in the station expansion program will make Toronto Hydro's system more resilient to sudden load demands, and will ensure sufficient capacity exists to ensure station reliability.

[10] If present in both the NA and RIP, the NA timing is used, as the NA is the more recent document.

The system needs are addressed through two segments: Downsview TS and Hydro One Contributions, as further discussed below.

E7.4.3.1 Downsview TS

The area affected by the Downsview TS segment consists of: Bathurst TS, Fairbank TS, Fairchild TS, and Finch TS. This area will be called the "Downsview Area" throughout the rest of this document. The Downsview Area is show in Figure 1.

In recent years, the Downsview Area has been attracting a large quantity of new load, and that trend is forecasted to persist into the future. On average, the area is forecasted to grow by 1.2 percent per annum over the next 10 years. /C

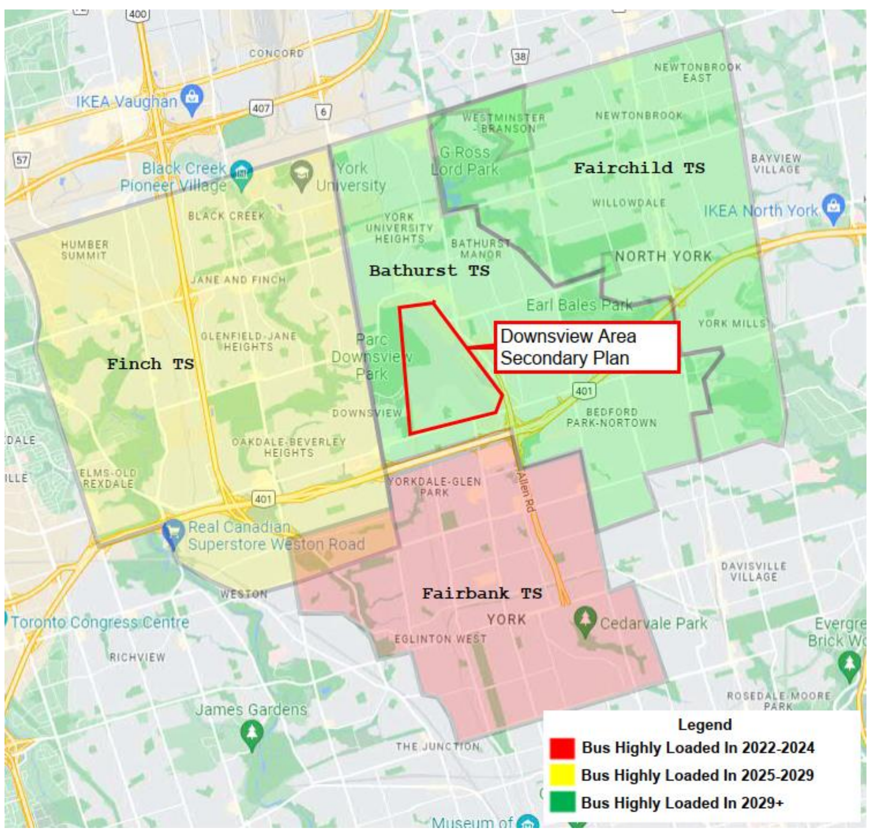

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Figure 1: Service Territories of Stations in the Downsview Area

1. Toronto Hydro's Peak Demand Forecast

Table 6 shows the existing load forecast for the stations in the Downsview Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

Table 6 : Non-Coincident Downsview Area 10-Yr Load Forecast[11]

Station	Summer LTR (MW)	2021 (Actuals)	2022 (Actuals)	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bathurst TS	361	67%	70%	60%	64%	64%	67%	69%	70%	70%	70%	69%
Fairbank TS	182	104%	91%	77%	71%	80%	81%	80%	81%	84%	86%	88%
Fairchild TS	346	61%	64%	60%	61%	63%	64%	65%	66%	68%	70%	71%
Finch TS	366	69%	72%	78%	81%	84%	86%	87%	89%	91%	93%	95%
Area Non-Coincident %	1255	71%	72%	68%	69%	72%	74%	75%	76%	78%	79%	80%

Finch TS is forecasted to be highly loaded (past 90%) by 2029, and Fairbank TS is forecasted to reach the 90% threshold just after 2031. Fairbank TS has historically been highly loaded, and is being relieved by the recent expansion work at Runnymede TS; nonetheless, the station remains highly loaded and requires subsequent relief. Fairchild TS has significant capacity in the Downsview Area, but cannot provide direct relief to the highly loaded Fairbank and Finch TSs, due to geography. /C

Despite remaining capacity at Bathurst and Fairchild TSs, and the practical challenges of utilizing Fairchild TS for relief, the entire Downsview Area is forecasted to reach 90% loading by 2037. This signals a lack of capacity at the regional level, which is needed to support new connections, growth, and electrification. Since existing station equipment is already sized to maximum ratings, Toronto Hydro determined that a new station will be needed to relieve regional constraints. Given the long lead time required to construct a new station, and considering the possibility of electrification demand (e.g. transportation and buildings) materialzing faster than expected, Toronto Hydro must therefore make necessary investments in the 2025-2029 rate period to ensure that new capacity is ready to serve the Area in the next decade.

[11] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

In addition to the impacts from the Peak Demand Forecast, Toronto Hydro is considering the longer-term impacts to the Downsview Area resulting from the Downsview Secondary Development Plan, and its Future Energy Scenarios outlooks. These are described in the subsections below.

~~1.~~2. Downsview Area Secondary Plan (“DASP”)

The Downsview Lands are approximately 210 hectares (520 acres) situated in the City of Toronto, bounded by Sheppard Avenue to the north, Allen Road to the East, Wilson Avenue to the south, and Downsview Park and the Park Commons to the west, as shown in Figure 2. The lands reside within the Bathurst TS service territory, as shown in Figure 1.

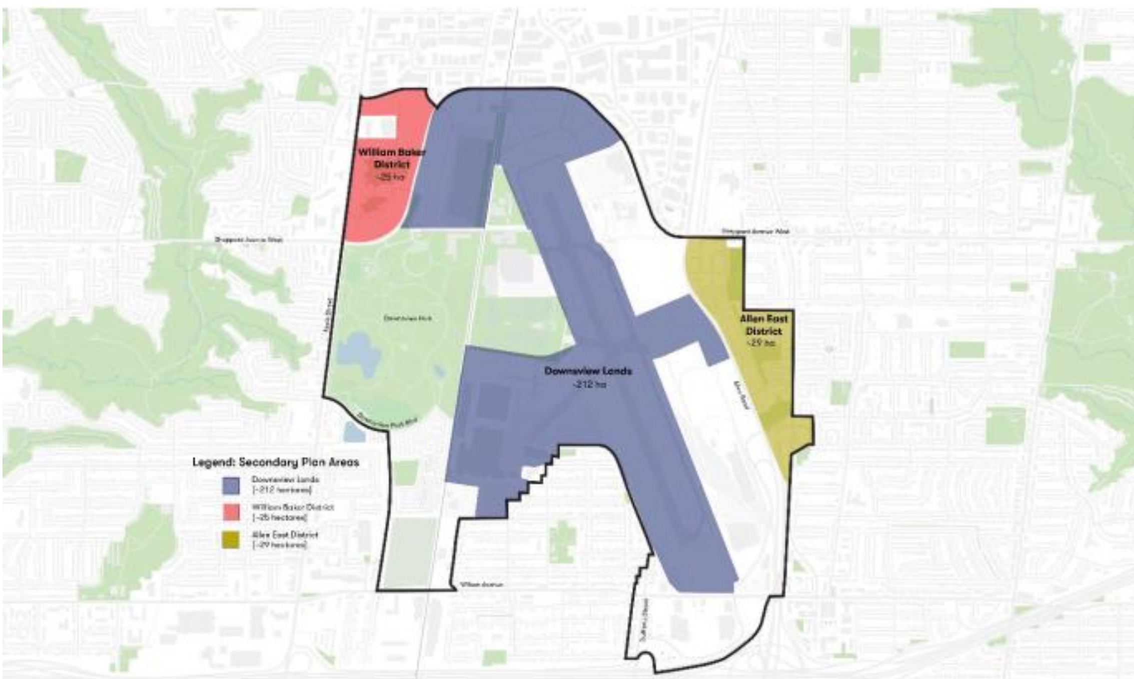

Figure 2: Proposed Downsview Secondary Plan Lands

The City of Toronto plans to redevelop the Lands into a dense new community as described in their Downsview Area Secondary Plan (“DASP”), published in 2017.[12] The DASP divides the Downsview Lands into districts and describes the expansion of each district with a mix of commercial, office, industrial and institutional buildings. The DASP preceded the city’s net zero 2040 plans but is to align

[12] City of Toronto, Downsview Area Secondary Plan, “online”, https://www.toronto.ca/wp-content/uploads/2017/11/902d-cp-official-plan-SP-7-Downsview.pdf

with the adoption of current day power demands of 6W per square foot and EV chargers for the projected EVs by 2045.

An independent party, DPM Energy, completed a preliminary study which estimates the electrical demand that will materialize from the DASP. This study suggests that load will begin to materialize in 2022 and could materialize up to: 103 MW by 2029, 180 MW by 2034, and 509 MW by 2051. This is equivalent to 8%, 14%, and 41% of the existing Downsview Area's Summer LTR of 1255 MW, as provided in

Table 6. As a result, supplying the Downsview Lands with existing regional capacity will not be feasible without capacity investments.

The Peak Demand Forecast only extends to 2031, and already considers load growth from the DASP. However, the DASP is expected to result in load growth up to 2051, with the majority of load materializing after 2031. Therefore, in order to ensure that cost-effective decisions are made now for the long term, Toronto Hydro has developed a 25 Year Forecast for the Downsview Area which considers the impact of the DASP from 2029 onwards. The 25 Year Forecast is based on the following assumptions:

1. **The annual load growth of the DASP for 2032-2051 is adjusted to 70 percent.**
   - Toronto Hydro's standard bus load forecasting methodology adjusts new customer load to 70% of the requested load in order to forecast bus load impacts. This reduction is based on historical results of customer load materialization.
2. **The 30 percent reduction to the DASP load for 2032-2051 is offset by:**
   - Load growth due to electrification of heating and transportation in the Downsview Area, in alignment with municipal and federal decarbonization goals.
   - General load growth in the Downsview Area, beyond the Downsview Lands.

Based on these assumptions, Toronto Hydro has adopted the 25 Year Forecast as the load forecast for the entire Downsview Area for post-2031. The results appear in Table 7.

Table 7: 25 Year Forecast for Downsview Area

Station	Summer LTR (MW)	2031	2034	2039	2044	2049	Year 100% Capacity is Reached
Bathurst TS	361	77%	81%	90%	99%	109%	2045
Fairbank TS	182	96%	101%	109%	118%	128%	2034
Fairchild TS	346	71%	71%	71%	71%	71%	N/A
Finch TS	366	99%	101%	105%	110%	115%	2032
Area Non-Coincident %	1255	85%	87%	92%	97%	103%	2046

/C

This forecast shows that by 2037, the Downsview Area as a whole will reach 90% loading, signaling a lack of capacity at the regional level. The forecast continues to show substantial load growth continuing past then, with no capacity remaining by 2046. Prior to that, 90% loading is forecasted at both Fairbank TS and Finch TS by 2031, and overloading by 2034. In summary, the 25 Year Forecast forecasts regional capacity constraints in the medium term, which worsen further into the long term. /C

~~2.~~3. Load Projections – FES

To consider the impacts that the electrification of heating and transportation, building stock growth, and DER integration may have on Toronto Hydro's station loading, Toronto Hydro completed the FES[7]. The FES produced six 30-year system and station bus load projections based on different scenarios.

The FES incorporates current growth trends, econometric factors, and electrification goals into its modeling, but does not incorporate any DASP load. The results from the FES outlooks are provided in Table 8.

Table 8 – FES Projections for the Downsview Area

Station	Summer LTR (MW)	2031	2034	2039	2044	2049	Year 100% Capacity is Reached[13]
Bathurst TS	361	84-94%	89-101%	95-114%	99-118%	98-122%	2034-N/A
Fairbank TS	182	120-132%	124-142%	130-167%	132-174%	131-180%	2021

[13] According to the FES only. As a result, this year may be earlier than what is provided in the Needs Assessment.

Station	Summer LTR (MW)	2031	2034	2039	2044	2049	Year 100% Capacity is Reached[13]
Fairchild TS	346	68-74%	69-78%	70-84%	70-85%	69-86%	N/A
Finch TS	366	113-122%	118-133%	124-150%	127-153%	126-156%	2024
Area Non-Coincident %	1255	93-102%	97-109%	102-122%	104-126%	103-129%	2030-2037

Across all FES projections, all but one station will become heavily loaded by 2035. Additionally, the Downsview Area is to become highly loaded between 2025-28, and overloaded between 2030-37. Consistent with Toronto Hydro's 25 Year Forecast, the FES projections indicate a regional need for additional capacity that increases with time, and foresees the possibility that constraints will arise even earlier. /C

~~3.~~4. Proposed Solution – New Downsview TS

In order to address both medium- and long-term regional needs for additional capacity in the Downsview Area, Toronto Hydro proposes to build a new transformer station, named Downsview TS. The objective of the new Downsview TS is both to provide load relief to the existing TSs in the Downsview Area, and to directly supply the new loads resulting from the DASP and electrification.

Downsview TS is proposed to be located within the Downsview Lands, within the Bathurst TS service territory. This location has been chosen so that it may directly supply local DASP loads, and because it is also a central location between Bathurst TS, Fairbank TS, and Finch TS. As a result, the station will be well-placed to offload the three highest loaded stations in the Downsview Area. Downsview TS will provide 174 MW of new capacity to supply the Downsview Area, increasing the Area's capacity by an additional 14%.

There will be both a Toronto Hydro and Hydro One component of work to construct the new Downsview TS. The Hydro One portion is discussed in E7.4.3.2 and involves the construction of a new Downsview Switching Station ("Downsview SS"), which will serve as the connection point to Hydro One's transmission network.

The construction of a new TS is a large project requiring a particularly long lead time, and for this reason, a portion of the work needed to build the new TS was advanced into the 2025-2029 rate period. In order to energize Downsview TS at the end of 2033, Toronto Hydro forecasts that work must begin in 2025. Toronto Hydro has planned for the Downsview TS project to proceed in two stages. The Planning and Preparation stage and the Construction and Energization stage.

The Planning and Preparation stage will proceed over the 2025-2029 rate period, and will include preparatory capital investments such as: property acquisition, property site preparation, construction of a new station building, high voltage circuit breakers and bus work, and partial construction or payments towards station assets.[14] The cost to complete this stage is forecasted to be $70.2 million.

The Construction and Energization stage will proceed starting in 2030 and will include the installation of the remaining electrical assets, the installation of station ancillary assets, and the commissioning and energization of all electrical assets. The remaining electrical assets include: a new 230 kV underground cables from Downsview SS, two new transformers, and one new switchgear. Toronto Hydro forecasts to spend $70.0 million during this stage, excluding the Hydro One contributions related to Downsview SS (see E7.4.3.2 – 1.).

Because the forecasted in-service date is beyond the range of the Peak Demand Forecast, the effect of Downsview TS is provided using the 25 Year Forecast and the FES load projections, and shown in Figure 3. With the addition of new capacity at Downsview TS, the Downsview Area loading is expected to be manageable out to 2049. FES Projections show that there is risk of Area overloading as early as 2036, and the magnitude of the potential overloading increases with time. To mitigate the risk of overloading in the long term, Downsview SS is proposed to be constructed with the provision to install a second DESN in the future, if and when it is needed. /C

[14] Site preparation will include items such as, but not limited to, the clearing of land, construction of a ground grid, installation of crushed stone, and a station fence.

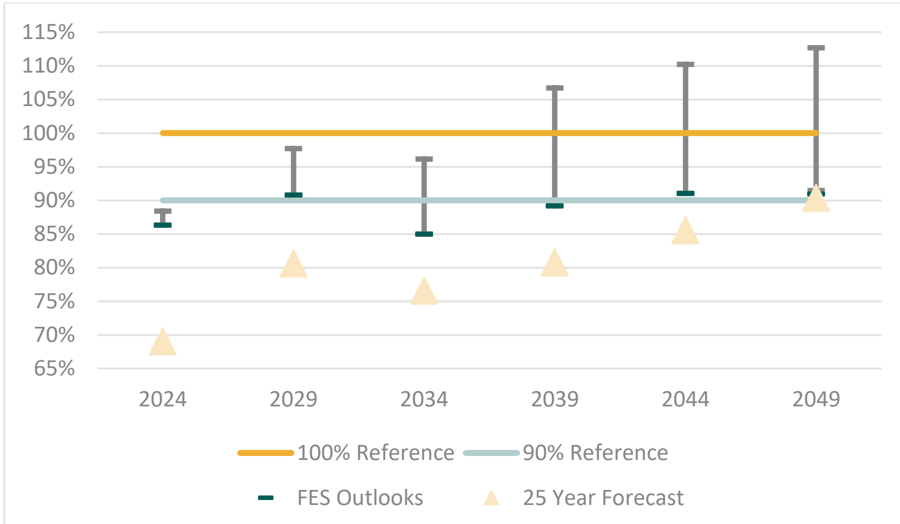

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Figure 3: Downsview Area Loading Outlooks After Downsview TS is In-Service

Toronto Hydro believes that the proposed solution strikes the right balance between the risk of capacity constraints and cost in least-regrets investment approach. Toronto Hydro will continue to monitor the actual and forecasted load of the Downsview Area to assess the risk of capacity constraints shortly after Downsview TS is completed. If this risk persists, Toronto Hydro may consider introducing another DESN into the Downsview Area at a later time; however, it would not be in the best interest of the ratepayer to invest immediately in two new DESNs. For this reason, the proposed solution includes only one new DESN, which is expected to provide adequate capacity until 2049. /C

E7.4.3.2 Hydro One Contributions

The most recent Needs Assessment reaffirms needs that were identified in the IRRP and highlights additional emerging needs. These needs are summarized in Table 26, Table 27, and in Section E7.4.7.

In response, Toronto Hydro plans to make capital contributions to Hydro One to carry out upgrades at Hydro One stations during the 2025-2029 rate period, as detailed in the following subsections.

1. New Downsview SS

Toronto Hydro plans to make a capital contribution to Hydro One over the 2025-2029 rate period to support their construction of a new Hydro One-owned Downsview SS. As discussed in section E7.4.3.1 above, the Downsview TS will provide additional capacity of 174 MW to alleviate forecasted constraints in the Downsview Area. Hydro One will support the project by constructing a new switching station, Downsview SS, to supply Downsview TS from the Hydro One 230 kV transmission line corridor. Toronto Hydro will construct and own the TS itself.

2. Sheppard TS Bus Expansion

The area affected by the Sheppard TS bus expansion consists of: Malvern TS, and Sheppard TS. This area will be called the “Sheppard Area” throughout the rest of this document. The Sheppard Area is shown in Figure 4.

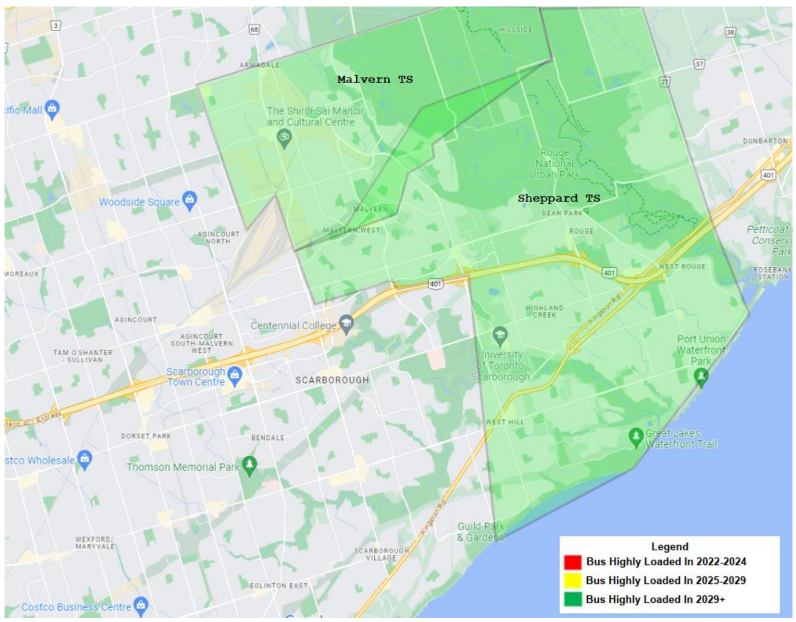

Figure 4 : Service Territories of Stations in the Sheppard Area

Table 9 shows the existing load forecast for the stations in the Sheppard Area based on firm connection requests, as provided in Toronto Hydro’s Peak Demand Forecast.

Table 9: Non-Coincident Sheppard Area 10-Yr Load Forecast[15]

Station	Summer LTR (MW)	2021 (Actuals)	2022 (Actuals)	2023	2024	2025	2026	2027	2028	2029	2030	2031
Malvern TS	176	60%	64%	60%	61%	62%	63%	63%	64%	66%	67%	68%
Sheppard TS	204	77%	70%	66%	66%	67%	64%	65%	67%	70%	72%	75%

/C

[15] Loading from Toronto Hydro’s Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

Station	Summer LTR (MW)	2021 (Actuals)	2022 (Actuals)	2023	2024	2025	2026	2027	2028	2029	2030	2031
Area Non-Coincident %	380	69%	67%	63%	64%	65%	63%	64%	66%	68%	70%	72%

Sheppard TS is forecasted to be 75% loaded by 2031, and since the Peak Demand Forecast has been produced, Toronto Hydro has received a new customer request for an additional 20 MW in the Sheppard TS service area. Malvern TS is forecasted to be loaded to a similar level, bringing the forecasted Area loading to 72% by 2031.

In addition, Sheppard TS is experiencing a lack of short circuit capacity, which is forecasted to persist into the future. As discussed in the Generation Protection, Monitoring, and Control Program ("GPMC Program"), short circuit capacity is a requirement to connect new DERs to Toronto Hydro's system. The GPMC Program also states that the available short circuit capacity of the Sheppard TS EZ bus in 2023 is -57.3 MVA, indicating a present need for relief and an inability to connect new DERs to the bus. Therefore, in order to ensure that its system does not act as a barrier to new DER connections, Toronto Hydro must relieve short circuit capacity constraints at Sheppard TS.

/C

The existing configuration of Sheppard TS also presents a unique opportunity to expand the station for a significantly reduced cost and in a shorter timeframe than comparable expansion projects.[16] This is because the station is already equipped with idle transformer windings, and as a result, the scope of work would not include transmission or transformation components. The expansion of Sheppard TS would only involve the installation of a new switchgear.

Toronto Hydro investigated alternatives to increase short circuit capacity at Sheppard TS, including the use of bus-tie reactors, a solution actively under consideration for other transformer stations in the current CIR period. However, due to technical limitations, such an investment is not suitable for this station. In 2016, Sheppard TS underwent an upgrade which replaced the outdoor air insulated switchgear with indoor Gas Insulated Switchgear ("GIS"). The newer enclosed and hermetically sealed design does not permit access to the switchgear bus that would allow the installation of a bus tie reactor.

[16] Comparable projects include the Runnymede TS expansion project from the 2015-2019 CIR, the Horner TS expansion project from the 2020-24 CIR, and the newly proposed Scarborough TS expansion project for the 2025-29 CIR.

Given the significantly reduced cost of expansion presented at Sheppard TS, the expansion of Sheppard TS would present a reliable and cost-effective solution to relieve the station's short circuit capacity constraints and enable new DER connections. The expansion would provide an estimated 126 MVA of short circuit capacity, with the additional benefit of 95 MW of new thermal capacity.[17]

3. Manby TS DESN Reconfigurations

The area affected by the Manby TS DESN Replacements Preparations ("DESN RPs") consists of: Horner TS, Manby TS, and Richview TS. This area will be called the "Manby Area" throughout the rest of this document. The Manby Area is shown in Figure 5.

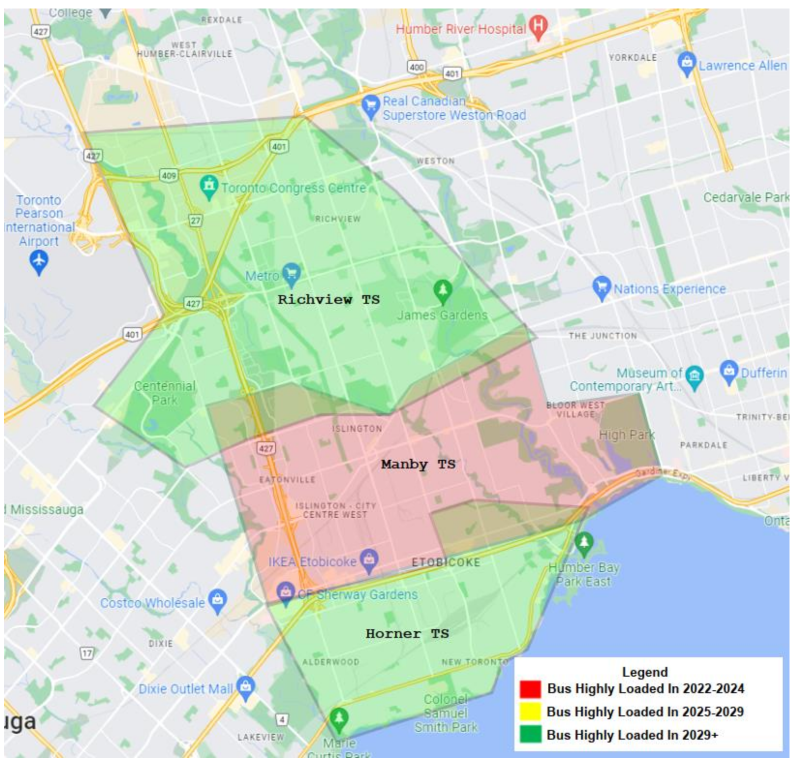

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Figure 5 : Service Territories of Stations in the Manby Area Table 10 shows the existing load forecast for the stations in the Manby Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

[17] Toronto Hydro is seeking for treatment of costs associated with the Sheppard TS bus expansion as eligible investments for provincial rate recovery under section 79.1 of the Ontario Energy Board Act, 1998. Please refer to Exhibit 2A, Tab 5, Schedule 1 for a summary of eligible investments and Schedules 5 and 6 for the breakdown of provincial rate protection amounts associated with the bus expansion.

Table 10: Non-Coincident Manby Area 10-Yr Load Forecast[18]

STATION	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Horner TS	366	40%	44%	47%	53%	58%	70%	72%	74%	75%	77%	78%
Manby TS	226	110%	97%	85%	86%	88%	77%	79%	81%	85%	88%	91%
Richview TS	460	63%	64%	60%	65%	64%	66%	61%	62%	64%	65%	65%
Area Non-Coincident %	1052	65%	64%	61%	65%	67%	70%	69%	70%	72%	74%	75%

/C

Due to the recent Horner TS expansion completed during the 2020-2024 rate period, the Manby Area is forecasted to have excess capacity to 2031. However, due to forecasted high loading at Manby TS specifically, and given the T13 and T14 transformers require renewal, the Hydro One 2022 Needs Assessment ("NA") Report recommends the upgrade of the Manby TS T13 and T14 transformers to the current standard size of 125 MVA. These upgrades are mentioned in the following Section "Hydro One Transformer Upgrades".

Because of the existing configuration at Manby TS, if the transformer replacements proceed without any reconfiguration of its associated DESN, then the DESN will actually decrease in capacity by 15 MW. Although the new T13 and T14 transformers will be rated at higher capacity, their additional capacity will be locked in idle windings, similar to the current configuration at Sheppard TS. However, the upgrade of the T13 and T14 transformers can provide additional renewal and long-term capacity benefits, if its DESN is reconfigured from the existing Jones configuration to a Bermondsey configuration in coordination with the transformer upgrades.[19][20]

The T3/T4 switchyard at Manby TS will require renewal in the near future. The existing T3/T4 DESN is under-rated which has made managing its load difficult. Rather than replace the T3/T4 switchyard like-for-like and the T13 and T14 transformers life-for-like, Toronto Hydro proposes to upgrade the T13 and T14 transformers (as recommended in the Needs Assessment) and also replace both the existing T13/T14 Jones switchyard and the T3/T4 Jones switchyard with one new Bermondsey

[18] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.
[19] A DESN in Jones configuration is composed of two single-winding transformers and two buses, with one transformer supplying each bus, and a normally-closed bus tie connecting the two buses to one another.
[20] A DESN in Bermondsey configuration is composed of two dual-winding transformers and two buses. One winding from each transformer supplies each bus, and a normally-open bus tie is installed between the buses.

switchyard. The new Bermondsey switchyard will be supplied by the upgraded T13 and T14. In summary, two existing Jones switchyards will be replaced with one new Bermondsey switchyard.

The near-term benefits of this proposal are as follows.

- No loss of capacity for the T13/T14 switchyard;
- Increase in station capacity by +16 MW once both switchyards are replaced;
- Higher reliability replacement plan for the T3/T4 switchyard, rather than replacing the switchyard "in-place" while still supplying customers;
- Fully-rated new Bermondsey switchyard can properly manage the combined load of the existing T3/T4 and T13/T14 DESNs;

In addition, this proposal presents two subsequent long-term options to increase station capacity at Manby TS when needed:

1. When the T3/T4 switchyard is replaced onto the new Bermondsey switchyard, the existing T3/T4 will be left idle in a similar configuration as what currently exists at Sheppard TS. As a result, Toronto Hydro can initiate for a new 60 MW switchyard to be installed using the idle windings, and thereby increase station capacity by 60 MW; or,
2. At the time when the third and last DESN at Manby TS requires renewal, if Toronto Hydro has not pursued the above option, then Toronto Hydro may be able to replace the last DESN and the idle T3/T4 with another new Bermondsey-configured DESN. This would increase the station capacity by approximately 123 MW.

Therefore because of both the near-term and long-term benefits to the renewal and upgrade of Manby TS, Toronto Hydro proposes to replace the existing T3/T4 and T13/T14 switchyards with a new Bermondsey switchyard, in coordination with the T13 and T14 transformer upgrades. This proposal is being referred to as "DESN Reconfigurations".

4. Hydro One Transformer Upgrades

To alleviate capacity constraints, Toronto Hydro proposes to invest in incremental upgrades to Hydro One transformers during the 2025-2029 rate period, as Hydro One completes the renewal of these end-of-life assets. The renewal plans are initiated by Hydro One and included in the Needs Assessment. Because of the coordination with renewal work, these investments present the greatest value-for-money in terms of $/MW, and are pursued even when the incremental capacity may not be immediately accessible.[21]

Based on the most recent Needs Assessment, City of Toronto Development Plans, and electrification risks to station capacity adequacy, Toronto Hydro has identified benefits in upgrading transformers at the stations listed in Table 11 below. These upgrades will immediately provide an estimated 226 MW of new capacity to Toronto Hydro's system, and up to another 272 MW of new capacity with further investments. For similar reasons, the Needs Assessment also recommends the upgrade of these units, with the exception of Carlaw TS.[22]

Hydro One will not plan to replace transformers until the units have reached end-of-life, typically after 45 years.[23] It is cost effective for Toronto Hydro to coordinate upgrades with Hydro One's renewal project schedule. Upgrades are only possible by removing and replacing the existing transformer. The cost to remove and replace the existing unit with a higher capacity unit outside of a Hydro One renewal project is approximately $10 million per unit, less asset depreciation. Alternatively, the incremental cost to upgrade a transformer in coordination with its renewal is approximately $0.8 million. Based on the needs identified from the NA and RIP as shown in Table 4 and Table 5, Toronto Hydro foresees the need for additional capacity at each of the stations in Table 11. Given the long life of these assets and the cost efficiencies achieved by coordinating with Hydro One's renewal schedule, Toronto Hydro has determined that it is prudent to invest in the incremental transformer upgrades listed in Table 11 to ensure that transformation capacity does not become a bottleneck to station capacity over the long term.

[21] Additional investment(s) may be needed following the transformer upgrade to realize the new capacity. For example, the station switchgear may need to be replaced.

[22] The Carlaw TS T1/T2 transformer renewals are not included the Hydro One NA Report, but their timing for renewal approaches the end of the 2025-2029 CIR rate period. Toronto Hydro proposes to prioritize their replacement and upgrade to support capacity needs identified at the adjacent Basin TS, as noted in the NA and RIP and referenced in Table 5. The East Harbour Master Plan and Port Lands development plans will intensify capacity needs at Basin TS.

[23] Kinectrics "Useful Life of Assets" Report, filed in the EB-2010-0142 application (Exhibit Q1, Tab 2)

Table 11: List of Toronto Hydro Owned Busses Connect to Hydro One Transformer Replacement

Project	Transformer Ratings (MVA)		Immediate New Capacity[24] (MW)	Potential New Capacity[25] (MW)
	Existing	New		
Basin TS – T3/T5 Upgrade	75	100	36	-
Carlaw TS – T1/T2 Upgrade[22]	75	100	54	-
Duplex TS – T1/T2 Upgrade	75	100	-	43
Duplex TS – T3/T4 Upgrade	75	100	-	16
Leslie TS – T1 Upgrade	125	125	-	91
Manby TS – T13/T14 Upgrade	93	125	16	60-122
Scarborough TS – T23 Upgrade	125	125[26]	38	-
Strachan TS – T14 Upgrade	75	100	53	-
Strachan TS – T13/T15 Upgrade	75	100	29	-
Total			**226**	**210-272**

E7.4.4 Expenditure Plan

Spending in the Stations Expansion program over the 2020-2024 rate period was forecasted to be $139.9 million. Toronto Hydro proposes to spend $121.9 million over the 2025-2029 rate period to add 321 MW of new capacity to its system, and contribute to an additional 174 MW of capacity /C realized in 2030-2034.[27] Forecasted growth, largely driven by City of Toronto Development plans, is driving the need for substantial new capacity to be added to Toronto Hydro's system, resulting in the need for increased expenditures.

Table 12: Historical & Forecast Program Costs by Segments ($ Millions)

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[24] New capacity which will be realized following the Hydro One transformer(s) upgrade(s)

[25] Additional investment(s) will be needed following the Hydro One transformer upgrade to realize the new capacity. For example, the station switchgear may need to be replaced, a new switchyard may need to be installed, or an additional transformer may need to be upgraded.
Toronto Hydro replaces end-of-life transformer station switchgear in the Station Renewal program (See Exhibit 2B, Section E6.6 Stations Renewal – Section E6.6.3.1 sub-section 1 TS Switchgear). /C

[26] Although the Scarborough T23's rating will not change, during the replacement components associated with the unit which limit station capacity will be upgraded, resulting in new capacity.

[27] The Downsview TS project will contribute 174 MW of new capacity and is forecasted to come in-service during the 2030-2034 rate period. /C

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Copeland TS Expansion	7.5	35.1	26.5	6.3	4.0	-	-	-	-	-
Hydro One Contributions	10.7	15.2	21.0	11.5	2.1	7.8	4.0	12.6	14.8	12.5
Downsview TS	-	-	-	-	-	3.2	3.9	9.6	25.9	27.7
Total	**18.2**	**50.3**	**47.5**	**17.8**	**6.1**	**11.0**	**7.8**	**22.2**	**40.7**	**40.2**

Over the 2020-2024 rate period, Toronto Hydro forecasts to spend $139.9 million in its Stations Expansion Program, which is a small overspend of $8.2 million or 6 percent relative to the $131.7 million forecasted in the 2020-2024 Distribution System Plan.[28]

This variance is mostly attributable to variances in the Hydro One Contributions segment, with a variance of $7.1 million. The major sources of variances in this segment result from: a Copeland TS Phase 1 True-Up payment, switchyard expansions at Bermondsey TS and Richview TS, Hydro One support for a new supply cable between Carlaw TS and Gerrard TS. Each of these sources is included in the Reactive Hydro One Contribution subsegment, which by its nature is challenging to forecast.

The proposed projects in the Stations Expansion program will address capacity constraints in areas identified by the Hydro One's 2022 Needs Assessment ("NA") Report, and will coordinate with the sustainment plans outlined in the Report. Given the complexity and size of these individual projects, these projects entail extensive coordination with Hydro One and other stakeholders (such as contractors, vendors, public etc.), long lead times for ordering equipment, and logistical challenges in heavy electrical equipment delivery. Due to these challenges, the Stations Expansion program is susceptible to fluctuations in spending from year-to-year.

E7.4.4.1 2020-2024 Variance Analysis – Copeland TS Expansion

Copeland TS Phase 2 expansion work commenced in 2017 and is expected to be completed in 2024. Table 13 below provides the cost summary with Actual and Bridge amounts for Phase 2. Over the 2020-2024 rate period, Toronto Hydro forecasts to spend $79.5 million on Copeland TS Phase 2, which is which is aligned with the $78.4 million forecasted in the 2020-2024 DSP.

[28] Less the Local Demand Response segment, which has moved to the Non-Wires Alternatives Program, Section E7.2

Table 13: 2020-2024 Budget (Actual/Bridge/Forecast) Copeland TS – Phase 2 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Copeland TS – Phase 2	7.5	35.1	26.5	6.3	4.0	0	0	0	0	0

An engineering, procurement, and construction (EPC) contractor was selected through a competitive bid process in 2020 and the vast majority of the project costs are incurred in the 2020-2024 rate period. Phase 2 of Copeland TS is expected to complete in early 2024, therefore no expansion cost is forecasted for the period of 2025-2029. Table 14 below summarizes the annual spending on Copeland Phase 2.

Table 14: Copeland Phase 2 Annual Budget Comparison ($ Millions)

Year	Initial Budget (EB-2018-0165)	Current
2017	0.5	0.3
2018	1.8	0.2
2019	7.8	3.5
2020	8.9	7.5
2021	29.7	35.1
2022	38.8	26.5
2023	1.0	6.3
2024	0	4.0
Total	**88.5**	**83.4**

Overall, the total project cost is expected to be $5.1 million below the initial total project cost and the contingency portion of the budget is not utilized. Cost savings arise primarily from more efficient execution and labour expenses, better procurement agreements for major equipment, and experience with execution and incorporation of lessons learned from Copeland Phase 1.

The EPC contractor selection took slightly longer and EPC contractor started work in 2020, whereas it was initially planned in 2019. Thus, the entire schedule and spending profile is shifted later by approximately a year. Costs were lower in 2019 due to planned design work by the EPC contractor starting in 2020 rather than 2019.

In mid-2020, the EPC contractor mobilized to site and pre-construction works and evaluation of existing site conditions was completed. By end of 2020, design progressed to 50 percent and procurement operations commenced. Project management and ancillary costs ramped up in 2020 and continued throughout to the end of the project.

In 2021, project spending was $5.4 million higher than initial plan due to completion of the majority of procurement of major electrical assets slightly ahead of plan. In particular, three Medium Voltage ("MV") Gas-Insulated Switchgears ("GIS"), three MV Air-Insulated Switchgears ("AIS"), High Voltage ("HV") cable, MV cable, and Protection and Control ("P&C") control equipment were delivered to site in 2021. Manufacturing was underway for the three Gas-Insulated Transformers ("GIT") and approximately 47 percent of their costs were incurred by end of 2021. Furthermore, all design was completed (except for 2 percent remaining on mechanical and structural design and a few electrical studies.)

Assembly, installation, testing, and commissioning of the three GIS and three AIS was completed in 2022. In addition, the three GITs were delivered to site from Japan in late 2022. Installation of HV and MV cable, P&C equipment and GITs progressed. Spending in 2022 was $12.3 million lower than initial plan due some procurement work completed earlier in 2021, and electrical equipment construction work continuing into 2023.

Spending in 2023 is $5.3 million higher than initial plan due to construction work continuing into 2023 whereas they were planned to be completed in 2022 in initial version. In particular, assembly, installation, testing, and commissioning of the three GITs and P&C equipment continued into 2023. Energization of major electrical equipment, including all three GITs, will be carried out in 2023.

Full system integration testing will commence near the end of 2023 and continue into 2024. Project closeout, site restoration and final site landscaping works is expected to be completed in early 2024.

2020-2024 Variance Analysis – Hydro One Contributions

Table 15 below provides the 2020-2024 variances for each project requiring Hydro One Contributions, as compared to the 2020-2024 DSP. Toronto Hydro forecasts an overspending of $7.1 million relative to the $53.3 million forecasted in the 2020-2024 DSP.

Table 15: Hydro One Contributions 2020-2024 Variances ($ Millions)

Subsegments	2020-2024 Planned	2020-2024 Actual/Forecast Cost	Variance
Horner Expansion	34.4	29.2	-5.2
Hydro One Transformer Upgrades	3.1	6.3	+3.2
Finch TS B-Y Bus Replacement	4.1	0	-4.1
Reactive Hydro One Contribution and True-Up Costs	11.7	24.9	+13.2
Total	**53.3**	**60.4**	**+7.1**

1. **Horner TS Expansion**

In the 2020-2024 rate application, Toronto Hydro forecasted a $34.4 million capital contribution to Hydro One for the Horner TS expansion based on a Class C estimate provided by Hydro One at the time. The actual costs incurred over 2020-2024 was $29.2 M, but a true-up payment may be required in the 2025-2029 rate period.

2. **Hydro One Transformer Upgrades:**

Over the 2020-2024 rate period, Toronto Hydro forecasts to contribute $6.3 million to Hydro One to upgrade existing Hydro One-owned power transformers. This will result in an overspend of $3.2 million compared to the forecast of $3.1 million in the 2020-2024 rate application. The projects are driven by Hydro One sustainment plans and new customer connections. Major sources of variance are as follows.

- **Carry-over transformer upgrades from the 2015-2019 rate period:** additional $2.7 million for lagging payments or to complete work initially forecasted to be complete by 2019, at Cecil TS, Dufferin TS, and Main TS.
- **Additional transformer upgrades:** additional $1.8 million capital contribution to Hydro One to upgrade transformers at Bridgman TS and Strachan TS, which was not included in the 2020-2024 DSP due to the timing of Hydro One's sustainment plans.
- **Variances to costs of proposed projects:** less $1.5 million capital contribution to Hydro One for planned transformer upgrades at Charles TS, Duplex TS, and Windsor TS. Hydro One is forecasted to charge an additional $1 million for the Charles TS transformers, the Duplex TS transformers have been deferred to the 2025-29 rate period, and Hydro One did not charge to upgrade the transformers at Windsor TS due to downsizing other equipment.

3. Finch TS B-Y Replacement

In the 2020-2024 rate application, Toronto Hydro proposed to replace Finch BY bus in coordination with Hydro One for a contribution of $4.1 million; however, Hydro One deferred the BY replacement to beyond 2025. To address a progressing failure risk, Toronto Hydro decided to replace the end-of-life circuit breakers and disconnect switches on the BY bus instead of waiting for the entire BY bus to be replaced.[29] Therefore, by pursing this alternative through the Stations Renewal Program, this Hydro One Contribution was never made and resulted in a variance of -$4.1 million.

4. Reactive Hydro One Contribution and True-Up Costs:

In the 2020-2024 rate application, Toronto Hydro allocated $11.7 million for reactive Hydro One contributions to support expansion projects or true-up costs unforeseen at the time of the application. Toronto Hydro forecasts to contribute $24.9 million over the 2020-2024 rate period for these reasons, resulting in an overspend of $13.2 million.

Pursuant to applicable cost recovery agreements (including criteria regarding cost reconciliation review), Toronto Hydro incurred $9.9 million to reconcile past Hydro One capital contributions to Copeland TS Phase 1. Such reconciliations are typically based on actual asset or station loading and project in-service anniversaries, making the costs difficult to forecast in advance. In particular for this project, $5.7 million was incurred due to reduced station loading, and $4.2 million was incurred due to additional spend by Hydro One relative to their CCRA estimate.[30]

Toronto Hydro forecasts to contribute $10.9 million to Hydro One for the following expansion projects which could not be estimated at the time of the previous application.

- **Switchyard expansions at Bermondsey TS and Richview TS:** These projects will expand the switchyards at the respective stations by six and four circuit breakers, permitting new feeders to access stranded station capacity. A forecasted $8.5 million capital contribution is required.
- **New supply cable between Carlaw TS and Gerrard TS:** This project will increase the capacity of Carlaw TS by 20 MVA and resulted in a Hydro One contribution of $2.4 million.

[29] Please refer to the Stations Renewal Program Section E6.6.4.1 “TS Segment Expenditure Plan”, subsection “TS Outdoor Breaker – 2020-2024 Variance Analysis”.
[30] Connection Cost Recovery Agreement

Finally, Toronto Hydro has allocated a remaining $1.9 million in 2024 for additional unforeseen Hydro One Reactive contributions, in the form of cost variances from current forecasts.

E7.4.4.2 2025-2029 Expenditures - Downsview TS

Toronto Hydro forecasts to spend $70.2 million on Downsview TS during the Planning and Preparation stage over the 2025-2029 rate period, and expects to spend another $70 million over the Construction and Energization stage over the 2030-2034 rate period. Downsview TS is expected to complete in late 2033. An annual breakdown of the expenditures is shown below in Table 16.

Table 16: 2025-2029 Budget Downsview TS ($ Millions)

	Forecast – Planning and Preparation					Forecast – Construction & Energization				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Downsview TS	3.2	3.9	9.6	25.9	27.7	30.7	24.0	7.6	7.7	--

1. **Downsview TS – Planning and Preparation**

The Downsview TS project will be a large and complex project for Toronto Hydro, with only the Copeland TS project being comparable.

The Planning and Preparation stage will involve the portion of work completed in the 2025-2029 rate period, which will involve the: procurement and preparation of a new site, installation of 230 kV station assets, new building construction, and partial work on remaining station assets. The expenditures for this scope are forecasted to total $70.2 million over the period with $14.6 million included in the rate base when civil assets are completed. The remaining forecasted spend is related to electrical assets which will be energized when the station is completed in 2033, and will not be included in the rate base until such time.

There are four major activities to be completed in the 2025-2029 rate period: contractor Request for Proposal ("RFP"), design and engineering, major asset procurement, and construction or installation of some major assets.

A summary of the Downsview TS – Planning and Preparation stage schedule and annual cost is provided below in Table 17: Summary Schedule and Annual Cost of Downsview TS – .

1 **Table 17: Summary Schedule and Annual Cost of Downsview TS – Planning and Preparation**

Year	Budget ($ Millions)	Work Schedule
2025	3.2	• Partial Property Acquisition and Site Preparation
2026	3.9	• Completion of Property Acquisition and Site Preparation • Design of 230 kV bus work and disconnect switches
2027	9.6	• Procurement of 230 kV bus work and disconnect switches • Design of 230 kV circuit breakers and procurement • Design of 230 kV underground circuits and supporting civil structures • Design of switchgear building • Procurement of construction equipment and materials for new building
2028	25.9	• Installation of 230 kV bus work and disconnect switches • Partial installation of 230 kV circuit breakers and foundations • Partial construction of civil structures for 230 kV underground circuits • Partial construction of switchgear building • Partial design of power transformers, foundations, fire walls, fire suppression, and oil containment systems
2029	27.7	• Completed installation of 230 kV circuit breakers and foundations • Continued construction of civil structures for 230 kV underground circuits, and partial procurement of 230 kV circuits and protection systems • Completed construction of switchgear building • Completed design for power transformers and supporting assets • Partial procurement of first power transformer • Procurement of materials for power transformer foundations and oil containment systems • Design and partial procurement of 27.6 kV switchgear • Design and partial procurement of station AC, DC, and ancillary services

2. Downsview TS – Construction and Energization

The Construction and Energization stage will involve work completed starting in 2030 until commissioning of the new station in 2033. Work in this stage will involve the: completion of 230 kV underground circuits, installation of power transformers, installation of switchgear, installation of station services, and overall commissioning. The expenditures for this scope are estimated to total $70 million over the period.

A summary of the Downsview TS – Construction and Energization stage schedule and annual cost is provided below in Table 18.

Table 18: Summary Schedule and Annual Cost of Downsview TS Construction and Energization Stage

Year	Budget ($ Millions)	Work Schedule
2030	30.7	• Completed construction of civil structures for 230 kV underground circuits • Completed procurement of 230 kV circuits and protection systems • Partial installation of 230 kV circuits and protection systems • Installation of foundations and oil containment systems of power transformers • Partial procurement of first and second power transformers • Delivery of 27.6 kV switchgear • Completed procurement and partial installation of station AC, DC, and ancillary services
2031	24.0	• Completed installation of 230 kV circuits and protection systems • Delivery and installation of first power transformer • Partial procurement of second power transformer • Installation of fire wall between first and second transformer • Partial installation of 27.6 kV switchgear • Completed installation of station AC, DC, and ancillary services

Year	Budget ($ Millions)	Work Schedule
2032	7.6	• Delivery and installation of second power transformer • Completed installation of 27.6 kV switchgear
2033	7.7	• Installation of fire suppression systems for power transformers • Final commissioning of power transformers, 27.6 kV switchgear, and integrated protection systems with Hydro One

E7.4.4.3 2025-2029 Expenditures - Hydro One Contributions

Toronto Hydro forecasts to spend $51.7 million on Hydro One capital contributions over the 2025-2029 rate period. The expenditures include contributions to Hydro One for stations expansions and for transformer upgrades. These projects are planned based on the Needs Assessment (see below at Section 7.4.7 Regional Planning Needs). Additionally, contributions towards the Hydro One-owned Downsview SS are included. /C

Table 19: 2020-2029 Budget (Actual/Bridge/Forecast): Hydro One Contribution ($ Millions)

	Actual			Bridge		Forecast					
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	
Horner TS Expansion	8.5	5.0	15.7	--	--	--	--	--	--	--	
Finch TS B-Y Bus Replacement	--	--	--	--	--	--	--	--	--	--	
Downsview SS	--	--	--	--	--	--	0.6	1.7	2.9	0.6	/C
Sheppard TS Bus Expansion	--	--	--	--	--	--	0.5	4.5	5.0	5.0	
Manby TS DESN Reconfigurations	--	--	--	--	--	--	0.5	3.5	4.0	4.0	
Hydro One Transformer Upgrades	1.1	--	2.5	2.5	0.2	4.3	0.4	1.6	1.6	1.6	
Reactive Hydro One Contributions & True-Up Costs	1.1	10.1	2.5	9.0	1.9	3.5	2.0	1.3	1.3	1.3	
Total	**10.7**	**15.1**	**21.0**	**11.5**	**2.1**	**7.8**	**4.0**	**12.6**	**14.8**	**12.5**	/C

1. Hydro One Switching Station for Downsview TS

Based on high level estimates from Hydro One, Toronto Hydro forecasts to contribute $5.8 million over the 2025-2029 rate period to Hydro One as an initial contribution towards Hydro One's Downsview Switching Station ("Downsview SS"). Downsview SS is expected to be largely constructed during the 2030-2034 period. As a result, Toronto Hydro is only forecasting expenses over the 2025-2029 rate period to be associated with the procurement of land for and the site preparation of the new SS.

Table 20: Downsview TS Expansion Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Downsview SS	0.0	2025
	0.6	2026
	1.7	2027
	2.9	2028
	0.6	2029

2. Sheppard TS Bus Expansion /C

In order to install a new bus at Sheppard TS, Toronto Hydro forecasts to contribute $15.0 million to Hydro One over the 2025-2029 rate period. The forecasted annual expenditures are provided in Table 21 below.

Because this project is still in its early stages, Hydro One has not been able to provide Toronto Hydro with a cost estimate at the time of this filing. However, Toronto Hydro has estimated expenditures based on the scope of work, which is similar to its TS switchgear installations from its Stations Renewal Program and from its Copeland Phase 1 and Phase 2 expansion projects.

The scope of work includes the installation of a new gas-insulated switchgear (GIS) comprised of six feeder circuit breakers, three padmounted feeder-tie disconnect switches, P&C devices, and a new building to house the GIS and P&C devices.

Table 21: Sheppard TS Bus Expansion Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Sheppard TS Bus Expansion	0	2025
	0.5	2026

Project	Expenditures ($ Millions)	Payment Year
	4.5	2027
	5.0	2028
	5.0	2029

3. Manby TS DESN Reconfigurations

In order to replace two Jones switchyards with one Bermondsey switchyard at Manby TS, for both capacity and renewal benefits, Toronto Hydro forecasts to contribute $12.0 million to Hydro One over the 2025-2029 rate period. The forecasted annual expenditures are provided in Table 22 below.

This project is still in its planning phase with Hydro One, due to the need to coordinate with and adapt Hydro One's existing T13/T14 transformer upgrade plans, which they have proposed for 2030. Because the T13/T14 upgrade is planned to take place seven years into the future from the time of this filing, Hydro One has not been able to develop a scope of work at this time. Similarly, Hydro One also has not been able to provide Toronto Hydro with a cost estimate at the time of this filing.

As a result, Toronto Hydro has estimated the scope of work involved, and has used this to estimate the needed Hydro One contributions. Consequently, there is more uncertainty in this expenditure forecast compared to the other projects proposed in this Program.

However, Toronto Hydro will need to provide its capital contribution to Hydro One during the 2025-2029 rate period, and that the capital contribution for this project will be too substantial to be managed by the Reactive Hydro One Contributions subsegment. Therefore, Toronto Hydro has elected to budget for this project separately, and has produced the best expenditure forecast it can with the information available at this time.

Table 22: Manby TS DESN Reconfigurations Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Manby TS DESN Reconfigurations	0	2025
	0.5	2026
	3.5	2027
	4.0	2028
	4.0	2029

4. Hydro One Transformer Upgrades

Toronto Hydro forecasts to contribute $9.5 million to Hydro One over the 2025-2029 rate period, in order to upgrade certain end-of-life transformers during their natural renewal projects. Table 23 below outlines the contributions to Hydro One by project, and the year the contribution is expected to be made.

The cost for each project was forecasted based on the actual costs of transformer upgrade projects completed or in-progress over the 2020-2024 rate period. The timing of each project has been provided in the NA assessment, which has been used to forecast when each capital contribution will be required, based on historical timing trends.

Table 23: Hydro One Transformer Upgrades Payment Breakdown

Hydro One Transformer Upgrades	Expenditures ($ Millions)	Payment Year
Basin TS – T3/T5	1.6	2025
Carlaw TS – T1/T2	1.6	2029
Duplex TS – T1/T2	1.6	2025
Duplex TS – T3/T4	1.6	2028
Leslie TS – T1	0.3	2025
Scarborough TS – T23	0.4	2026
Strachan TS – T14	0.8	2025
Strachan TS – T13/T15	1.6	2027

5. Reactive Hydro One Contributions

As noted in Section E7.4.4.1, **2020-2024 Variance Analysis – Hydro One Contributions**, Toronto Hydro forecasts to contribute $24.9 million over the 2020-2024 rate period towards Reactive Hydro One Contributions. This subsegment was first introduced during the 2020-2024 CIR based on previous experience of funding shortfalls as new, unbudgeted, Hydro One projects were initiated, or as unexpected Hydro One true-up costs were billed to Toronto Hydro. Examples of such Hydro One projects include transformer or cables upgrades, or the installation of new circuit breakers, which result in an incremental increase in capacity.

As predicted, there were indeed significant unexpected projects and true-up costs which developed during the 2020-2024 rate period, and the Reactive Hydro One Contributions subsegment is forecasted to mitigate (approximately half of) the unexpected spending in the Hydro One Contributions segment, as intended. Therefore, Toronto Hydro proposes this subsegment continue into the 2025-2029 rate period, as a continued mitigation measure since it again anticipates a need in the 2025-2029 rate period.

To this end, Toronto Hydro has allocated $9.4 million over the 2025-2029 rate period towards Reactive Hydro One Contributions. The annual expenditures are provided in Table 24 below.

Table 24 : Reactive Hydro One Contributions Annual Allocations

Subsegment	Expenditures ($ Millions)	Payment Year
Reactive Hydro One Contributions	3.5	2025
	2.0	2026
	1.3	2027
	1.3	2028
	1.3	2029

E7.4.5 Options Analysis

Toronto Hydro has identified and evaluated various options to address system needs, as outlined in the below sections.

E7.4.5.1 Options Comparison for the Downsview Area

To address the forecasted need for additional capacity in the Downsview area, Toronto Hydro considered several options including: Status Quo, Load Transfers, Non-Wires Solutions, Station Upgrades, New DESN(s), and a new Downsview TS. The key results of the Options studied are summarized in Table 29. Options were considered in order of increasing level of intervention, until an acceptable option was identified. Option 6 – building the new Downsview TS is the only option capable of meeting system needs with reasonable risks and quantity of load transfers. See Exhibit 2B, Section E7.4, Appendix A – Downsview Business Case for further details of the assessment of these options.

The options were assessed as follows:

- **Option 1 – Status Quo** was rejected. Status quo is never recommended when capacity constraints are identified, but this option illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress.
- **Option 2 – Load Transfers** was also rejected as it is only viable up until 2034. /C
- **Option 3 – NWSs** was rejected because it would not provide a long-term solution and had a very high execution risk. NWSs are designed to address short-to-medium term capacity constraints. The quantity of load that needs to be addressed is at a magnitude well in excess of levels achieved and planned to date (e.g. 10 MWs achieved and 30 MW planed compared to a need for 93 MW by 2044 and 162 MW by 2049).[31] /C
- **Option 4 – Station Upgrades** was considered, but all station equipment in the Downsview Area is already sized to maximum ratings and cannot be further upgraded. Therefore, this option is technically infeasible and was rejected.
- **Option 5 – New DESN(s)** was considered for each of the four existing stations within the Downsview Area; but only Finch TS could accommodate a new DESN. Although possible, a new DESN at Finch TS would be especially difficult to utilize effectively in the Downsview Area, due to: existing congestion, geographic barriers, and distance from the DASP area. These challenges translate into high execution risks, an expectation of stranded capacity at Finch TS (inaccessible to the rest of the Downsview Area), and an expectation for higher than typical load transfer costs. Finally, because Finch TS is remote from the DASP area and is not central to the broader Downsview Area, this Option is forecasted to require a high quantity of load transfers, specifically 129 MW by 2044 and 192 MW by 2049, to redistribute the new /C capacity across the Downsview Area. As a result of the many significant risks, challenges, and inefficiencies presented by Option 5, this Option was ultimately rejected.
- **Option 6 – Construction of Downsview TS** is the selected option. Because of the proposed placement of the new TS, it is suited to offload existing stations and directly supply the new DASP loads, which is the major driver of load growth in the broader Downsview Area. This results in a minimal execution risk in terms of addressing system needs once the new TS is in service. The construction of a new TS is a large and complex undertaking. Therefore, overall

[31] See E7.2.1.4

execution risk was evaluated as Medium. Because of the designed placement of the new TS, the required load transfers of this Option are less than in the previous Option 5 at: 55 MW by 2044 and 142 MW by 2049. Option 6 also includes a provision to address the risk of subsequent overloading in the long term by permitting a second DESN to be installed at the newly constructed TS, whereas no provision exists in Option 5. If if the second DESN is constructed by 2044, then the required load transfers of this option can be limited to 55 MW, rather than 142 MW by 2049. /C

1 **Table 25: Summary of Options Outcomes for the Downsview Area**

Option (Increasing in Level of Intervention)	Decision	Reason for Decision	Decision Criteria				
			Acceptable Long Term Solution	Cumulative Load Transfers or NWSs Required [by 2044/2049] (MW)	Operational + Customer Connection Risks	Execution Risk	Risk of Subsequent Overloading
1 – Status Quo	Reject	This Option is only viable as a short-term solution.	No	N/A – viable only for a short term	High	Medium	Forecasted Overload
2 – Load Transfers	Reject	This Option can only manage loading until 2034.	No	N/A – viable only for medium term	Low	Minimal	Forecasted Overload
3 – NWSs	Reject	NWSs are not designed to be long term solutions. Very high execution risk due to unprecedented quantity of NWSs needed.	No	93/162	High	Very High	Mitigated
4 – Station Upgrades	Reject	Technically infeasible: Station equipment is already sized to maximum ratings.	No	N/A	N/A	N/A	N/A
5 – New DESN(s)	Reject	High execution risks, likelihood of stranded capacity, and excessive quantity of load transfers drive the need for an alternative solution.	Yes	129/192	Minimal	High	Unmitigated
6 – New TS	**Accept**	Meets system needs with reasonable risks.	Yes	55/142	Minimal	Medium	Mitigated

/C

2

E7.4.5.2 Options for the Sheppard Area

In addition to the proposed option to address needs in the Sheppard TS Area, that is to install a new bus at Sheppard TS, two alternative options were considered: first, bus-tie reactors; and second, DER transfers. As mentioned in Section E7.4.3.2, 2. Sheppard TS Bus Expansion, the switchgear installed at Sheppard TS does not permit access to the switchgear bus that would allow the installation of a bus tie reactor. Therefore, due to technical limitations, this alternative option was rejected.

It is impractical, inefficient, and inconvenient for the affected customers to address short circuit capacity constraints through DER transfers to adjacent stations. For this option to be effective, Toronto Hydro would need to identify large DER customers, located near the border of a station's service territory, to be reconnected to a nearby station that has both sufficient thermal and short-circuit capacity. However, because of the geographical sparsity of large DER customers, it is rare to find enough such customers located near the border rather than in the interior. When such customers are located in the interior, there are notable drawback in pursuing the DER transfers option.

Let us consider the present case where Sheppard TS has a short circuit capacity constraint, and Malvern TS is technically available to reconnect large DER customers. In order to transfer a large DER customer located in the interior of the Sheppard TS territory, a feeder must run: from Malvern TS, through the boundary between Malvern and Sheppard TSs, and then into the interior of the Sheppard TS territory. Effectively, a Malvern TS feeder must extend further than any of the other Malvern TS feeders, and intrude into the Sheppard TS territory to reach the large DER customer. /C

Building such long feeder lengths results in high costs, reduced reliability of supply to the customer, and large voltage drops during feeder contingencies (planned or forced). Additionally, the intrusion of a feeder from another station results in unnecessary pole or cable chamber congestion, and the disruption of clear station service boundaries. For these reasons, the DER transfers option is impractical; however, the proposed option of installing a new bus addresses the short circuit capacity constraints and avoids these challenges.

The proposed option also introduces two large benefits not present with the alternative of DER transfers. First, the new bus at Sheppard will introduce an estimated 126 MVA of new short circuit capacity to the station, which not only will relieve the constraint, but will also provide new short circuit capacity to enable new DER growth at Sheppard TS. Second, the new bus will also introduce

95 MW of thermal capacity to the Sheppard Area to provide operational flexibility and support future demand driven by electrification.

In summary, the Sheppard TS bus expansion is the preferred option. /C

E7.4.5.3 Options for the Manby TS Area

The proposed Manby TS DESN reconfigurations project is being triggered by Hydro One's planned renewal and upgrade of its T13/T14 transformers as stated in the Needs Assessment, and by the upcoming need to renew the T3/T4 switchyard. As a result, there are only two options to consider are to either take advantage of the renewal opportunity to improve the station (as proposed), or to dismiss this opportunity.

For similar financial reasons as discussed with the Hydro One Transformer Upgrades subsegment in E7.4.3 Drivers and Need, if Toronto Hydro does not take the opportunity to improve the station during the upcoming renewal work, it will likely have to wait another 45 years before it has another opportunity to complete the proposed improvements or undertake upgrades at a significantly higher cost.

As discussed in the Manby TS DESN Reconfigurations subsection of E7.4.3 Drivers and Need, the proposed option has multiple short term and long-term benefits, related to capacity, reliability, and the execution of the renewal of Manby TS. Ultimately, this option will permit up to 139 MW of new capacity to be added in the long term. These benefits will be lost if the proposed DESN reconfigurations do not proceed.

Upon consideration of the FES, Toronto Hydro believes it is prudent to enable options to increase the capacity of Manby TS in the long term. Four of the six FES project that the Area will require additional capacity between 2035-2039. With the Horner TS expansion complete in the 2020-2024 rate period, there are presently no expansion options available in the Area other than the installation of a new TS, which was considered as the alternative to the Horner TS expansion.

To align with an investment philosophy of a least-regrets approach, Toronto Hydro should not dismiss the limited-time opportunity to enable Manby TS to be expanded in the future, when needed. In order to do this, Toronto Hydro must invest in the proposed Manby TS DESN reconfigurations project in coordination with Hydro One's T13/T14 transformer renewal project.

For this reason, and because of the other benefits discussed in E7.4.3 Drivers and Need, the proposed option was selected over the alternatives.

E7.4.6 Execution Risks & Mitigation

E7.4.6.1 Downsview TS

The Downsview TS segment is a large undertaking and involves multiple execution risks, which include:

- Given the complex nature of these projects, a host of inherent planning challenges and risks can impact overall project cost and execution, such as the length of time required to acquire permits;
- New Downsview TS site location and land purchase;
- Road moratoriums established by the City of Toronto;
- 230 kV U/G cable design and construction and Hydro One 230kV switching station design and construction – potential timeline issues;
- Engage Hydro One 230kV Switching Station Design and Construction;
- Logistical challenges in delivering electrical equipment into the city; and
- Coordination with distribution planners as well as with third parties.

Toronto Hydro will communicate key lessons learned from past projects to Downsview TS bidders during the RFP procurement process to mitigate project execution risks. In particular, Toronto Hydro will provide risk information associated with facility conditions and restrictions, logistical and transportation issues, unique specifications of major electrical equipment, and permitting issues. Coordination with Hydro One for switching station construction, the city new TS land and association on the new 230kV route will be the risks on the new TS's construction timeline.

Financial risks will be mitigated by pursuing a fixed-price, turn-key, EPC contract. A competitive bid process will result in a selection of one general contractor responsible for all the major tasks. This is expected to be completed in 2026.

Quality control risks will be mitigated via the use of reputable third-party firms with extensive electrical station construction experience to carry out verification and payment review/billing certification. A consulting engineering firm will be utilized to investigate and resolve emerging site issues and ensure that construction is carried out according to specifications.

E7.4.6.2 Hydro One Contribution

The following risks are associated with the execution of Hydro One contribution project:

- Schedule depends on Hydro One's ability to execute the work;
- Overall project cost is highly dependent on Hydro One estimates; and
- Additional tasks (such as installation of bus and feeder ties or other safeguard measures to protect Toronto Hydro assets during Hydro One asset replacement) may be identified during detailed equipment outage planning. If an identified task is performed by Toronto Hydro, it will increase the project's cost for Toronto Hydro.

To mitigate these risks, Toronto Hydro engages in active coordination with Hydro One through bi-monthly meetings and as-required on-site meetings with relevant stakeholders to remain aligned with Hydro One's latest sustainment plans.

E7.4.7 Regional Planning Needs

The following Table 26, Table 27, an dTable 28 (from the IRRP Needs Assessment Report), highlight the emerging needs that have been identified in the Toronto Region since the previous regional planning cycle, and reaffirms the near, medium, and long-term needs already identified in the previous RIP.[32] The tables below also highlight how the Stations Expansion program is expected to address these needs.

Table 26: New Needs Identified in the Needs Assessment

New Needs	Needs Assessment Section	Stations Expansion Program
End-of-Life (EOL) Assets	*7.1*	See E7.4.3.2, Section 2. – Hydro One Transformer Upgrades.
East Harbor / Port Lands Area and Basin TS – Transformation Capacity	*7.1.4*	Needs Assessment identified this need by long term planning, short term by replacing T3/5 with 100 MVA.

[32] See Exhibit 2B, Section B, Appendix A, B, C, D, and E for Regional Planning Reports.

1 **Table 27: Needs Identified in Previous RIP**

Needs Identified in Previous RIP	Needs Assessment Section	RIP Report Section	Stations Expansion Program
South-West Toronto – Station Capacity	7.2.1	7.2	Addressed with Horner expansion in 2020-2024 Stations Expansion plan.
Downtown District – Station Capacity	7.2.2	7.3	Addressed with Copeland TS - Phase 2 expansion in 2020-2024 Stations Expansion plan.
230 kV Richview x Manby Corridor – Line Capacity	7.2.3	7.4	Transmission network constraint. Not applicable to Toronto Hydro.
Supply Security – Breaker Failure at Manby West & East TS	7.2.4	7.6	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Leaside Autotransformer – Transformation Capacity	7.2.5	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
Voltage Instability of 115 kV Leaside Subsystem	7.2.5	Identified in Central Toronto Area IRRP report – Appendix E	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Leaside x Wiltshire Corridor – Line Capacity	7.2.6	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Manby Autotransformers – Transformation Capacity	4.2.7	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Manby West x Riverside Junction – Line Capacity	7.2.8	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Don Fleet JCT x Esplanade TS – Line Capacity	7.2.9	Identified in Central Toronto Area IRRP report – Appendix E	Transmission network constraint. Not applicable to Toronto Hydro.

Table 28: End-of-Life Assets – Metro Toronto Region

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Fairbank TS: T1/T3, T2/T4 Transformers	*2022-2023*	EOL transformers and other HV equipment are identified at these stations for replacement with similar type equipment of the same ratings (discussed further in Section 7.1.1.1 of Needs Assessment).	Current 50/83 MVA transformer is largest 115-27.6 kV standard size.
Fairchild TS: T1/T2 Transformers	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Leslie TS: T1 Transformer	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Runnymede TS: T3/T4 Transformers	*2021-2022*		Proposed 50/83 MVA transformer is largest 115-27.6 kV standard size.
Sheppard TS: T3/T4 Transformers	*2019-2020*		Toronto Hydro determined increase in capacity to larger 75/125 MVA transformer was not required.
Bridgman TS: T11/T12/T13 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2 of Needs Assessment	Included in 2015-2019 Stations Expansion plan.
Charles TS T3/T4 Transformers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.
Duplex TS: T1/T2 Transformers	*2023-2024*		Included in 2020-2024 Stations Expansion plan.
Strachan TS: T12 Transformer	*2020-2021*		Included in 2015-2019 Stations Expansion plan.
Bermondsey TS: T3/T4 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3 of Needs Assessment.	Identified as consideration for downsizing, therefore Not Applicable to Toronto Hydro. See section 7.1.1.3 of Needs Assessment for details.
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV breakers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Main TS: T3/T4 Transformers and 115 kV line disconnect switches	*2021-2022*		Included in 2015-2019 Stations Expansion plan.
Manby TS: T7, T9, T12 Autotransformers, T13 Step-Down Transformer and rebuild 230 kV yard	*2024-2025*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV C5E/C7E Underground Cable: Esplanade TS to Terauley TS	*2024-2025*	EOL Line section is identified for replacement with similar type equipment, and is discussed further in Section 7.1.1.4 of Needs Assessment.	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV H1L/H3L/H6LC/H8LC: Bloor Street JCT to Leaside JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV L9C/L12C: Leaside TS to Balfour JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.

E7.4.8 Flexibility Considerations

Depending on policy changes by all three levels of government, changes in customer preferences, and decarbonization efforts, there are a large range of outcomes from the energy transition which could impact Toronto Hydro's distribution system. For example, using the Future Energy Scenarios model, the impact of the high electrification/low efficiency scenario (NZ40 – Low) projects an unprecedented increase in system load which would translate into a significant level of additional investment for the Stations Expansion Program in order to meet such need. Table 29shows the estimated costs under this scenario.[33]

[33] See Exhibit 2B, Section D4, Appendix A – Future Energy Scenarios Overview and Appendix B – Future Energy Scenarios Report.

Table 29: Estimated Stations Expansion Investment Needed under Future Energy Scenarios NZ40-Low Efficiency Scenario

CIR Period	Estimated Investment Need ($M)[34]
2025-2029	95
2030-2034	191
2035-2039	527

/C

Scarborough TS Expansion

The Scarborough TS Expansion (included in Toronto Hydro's original evidence filed on November 17, 2023) entails installing a new Dual Element Spot Network ("DESN") to provide relief to the Horseshoe East area and support future load growth in this area. Growth in this particular area is driven in large part by the Golden Mile Secondary Development Plan ("GMSDP"). Adopted by the City of Toronto in 2020, the GMSDP which proposes a mixture of residential, commercial, and office building development in the area knowns as the Golden Mile – a 113 hectares (280 acres) piece of land, generally bounded by Victoria Park Avenue to the west, Ashtonbee Road/Hydro Corridor to the north, Birchmount Road to the East and an irregular boundary to the south, as shown in Figure 6 below.

/C

[34] This is the additional investment needed incremental to the 2025-2029 investment proposed in this Program, and incremental to the 2030-2034 expenditures forecasted for the Downsview TS and Scarborough TS expansion projects. No expenditures have been forecasted in this Program for 2035-2029. No inflation assumptions have been included.

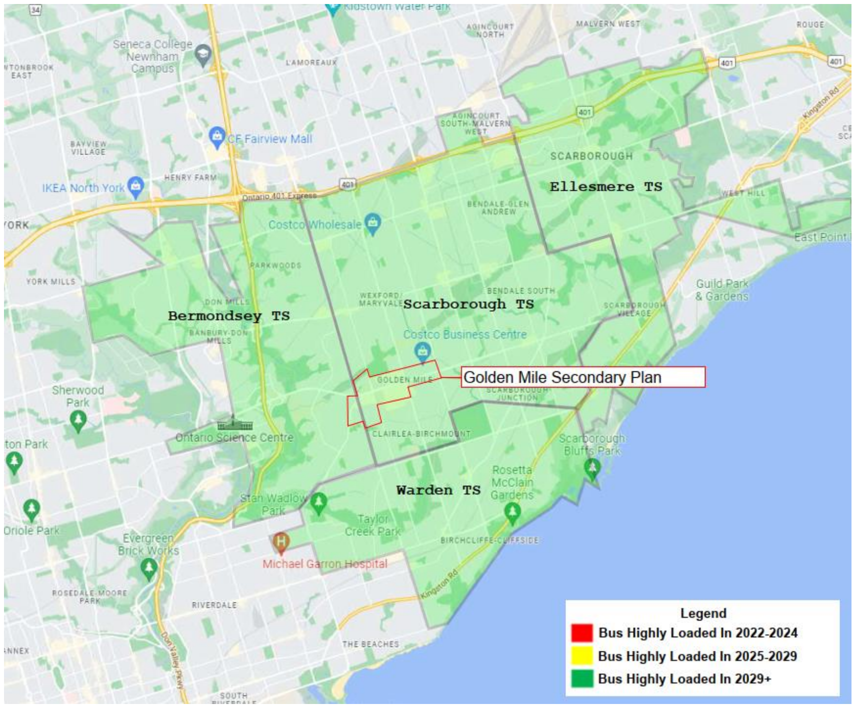


Figure 6: Service Territories of Stations in the Scarborough Area /C

Based on the updated System Peak Demand forecast filed on January 30, 2023, Toronto Hydro determined that the Scarborough TS expansion can reasonably be deferred from the 2025-2029 rate period and has amended its capital expenditure plan to exclude this investment. However, under different electrification assumptions (e.g higher uptake of electrified heat and transportation technologies), the Scarborough area could see faster and higher demand for electricity than currently expected. In an accelerated electrification scenario, as envisioned by the FES, Scarborough TS may require an expansion in the 2025-2029 period to ensure that grid is equipped to serve the evolving needs of customers in this area in the next decade and beyond.

If a higher need for electricity demand arises in the Scarborough area (or other parts of the City) due to faster uptake of electrified technologies or other growth drivers, Toronto Hydro needs to be able to invest to expand the capacity of its distribution system. The proposed regulatory flexibility mechanism (known as the Demand Related Variance Account outlined in Exhibit 1B, Tab 2, Schedule 1) would enable the utility to make additional prudent investments needed (such as Scarborough TS) in the 2025-2029 rate period.

Downsview TS Business Case

Table of Contents

1 EXECUTIVE SUMMARY

Project Name	Costs	
Downsview TS	$	192.2 M

This project will address forecasted capacity constraints in the Northwest portion of the City due to confirmed large customer requests, the Downsview Area Secondary Plan, and electrification.

The proposed solution is to install a new TS, Downsview TS, in the Downsview Area, roughly between Bathurst TS and Finch TS. This location will permit the new TS to supply the new developments arising from the Downsview Area Secondary Plan, as well as offload the heavily loaded Bathurst, Fairbank, and Finch TSs.

The scope of work involves procuring new land for the new station, and constructing new 230 kV underground cables and duct banks from a Hydro One station, a new building, two new transformers, and one new switchgear. Downsview TS will provide 174 MW of new capacity to supply the Area.

The project is expected to start in Q1 2025 with an in-service date set to Q4 2033. Given the long lead time required to construct a new station, the project will be completed over two stages – Planning and Preparation during 2025-2029 and Construction and Energization over 2030-2034.

The project cost is estimated to be $76.0 million over the 2025-2029 rate period and $116.2 million over the 2030-2034 rate period, including Hydro One contributions and inflation assumptions. Only $14.6 million of the project's estimated cost are planned to be capitalized in the 2025-2029 rate period. These costs are related to the completion of site acquisition and preparation, and the completion of civil construction. The remaining project costs will be capitalized at the completion of the project once the station has been energized.

2 BACKGROUND

2.1 Existing Regional Growth

The area under consideration in this Business Case consists of Bathurst TS, Fairbank TS, Fairchild TS, and Finch TS. This area is shown in Figure 1. This area will be called the "Downsview Area" throughout the rest of this document.

In recent years, the Downsview Area has been attracting a large quantity of new load, a trend that is forecasted to persist into the future. On average, the Downsview Area is forecasted to grow by 1.2% per annum.

Table 1 shows the existing load forecast for the stations in the Downsview Area based on firm connection requests. A station is considered to be highly loaded once loading reaches 90% or higher.

Finch TS is forecasted to be highly loaded (past 90%) by 2029, and Fairbank TS is forecasted to reach the 90% threshold just after 2031. Fairbank TS has historically been highly loaded, and is being relieved by the recent expansion work at Runnymede TS; nonetheless, the station remains highly loaded and requires subsequent relief. /C

In addition to the impacts from the Peak Demand Forecast, Toronto Hydro is considering the longer-term impacts to the Downsview Area resulting from the Downsview Secondary Development Plan, and its Future Energy Scenarios outlooks. These are described in the subsections below.

/C

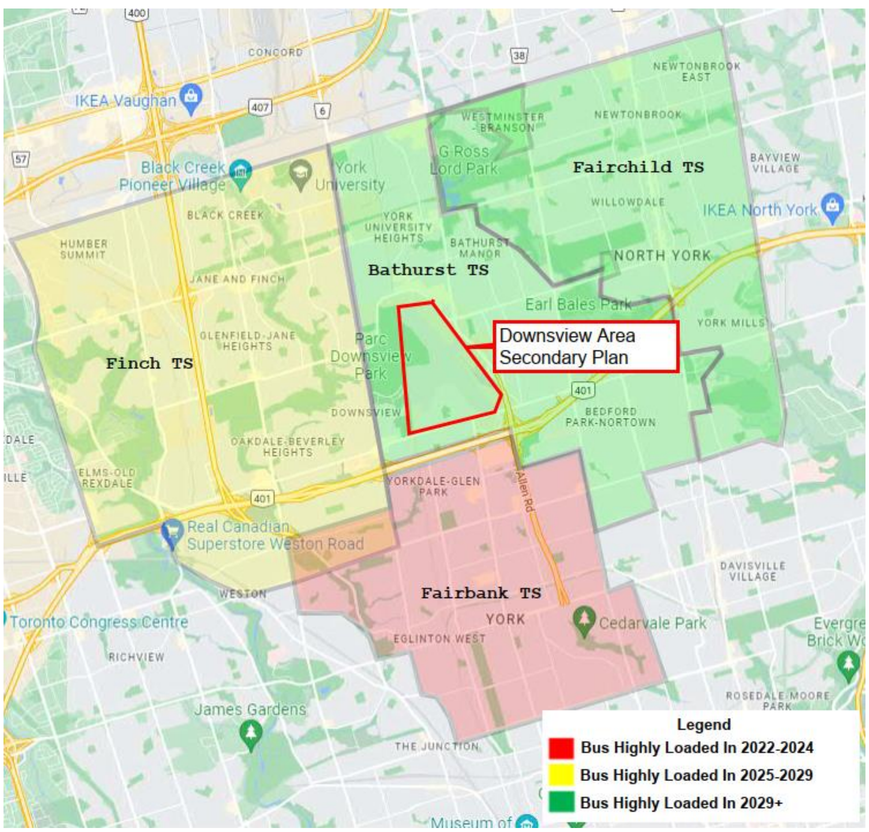


Figure 1 – Map of the Downsview Area and its Stations

Table 1 – Non-Coincident Downsview Area 10-Yr Load Forecast[1]

Station	Summer LTR (MW)	2021 (Actuals)	2022 (Actuals)	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bathurst TS	361	67%	70%	60%	64%	64%	67%	69%	70%	70%	70%	69%
Fairbank TS	182	104%	91%	77%	71%	80%	81%	80%	81%	84%	86%	88%
Fairchild TS	346	61%	64%	60%	61%	63%	64%	65%	66%	68%	70%	71%
Finch TS	366	69%	72%	78%	81%	84%	86%	87%	89%	91%	93%	95%
Area Non-Coincident %	1255	71%	72%	68%	69%	72%	74%	75%	76%	78%	79%	80%

/C

2.2 Downsview Area Secondary Plan

In 2017, the City of Toronto approved of the Downsview Area Secondary Plan ("DASP"). The area is generally bounded by Sheppard Avenue to the north, Allen Road to the East, Wilson Avenue to the south, and Downsview Park and the Park Commons to the west, as shown in Figure 2.

The DASP plans to expand each district with a mix of commercial, office, industrial and institutional buildings. Mid-rise buildings (10-14 storeys) will be built around the existing TTC Downsview station and lower mid-rise buildings (6-10 storeys). The Allen East District will be primarily be a residential area of 3,500 dwelling units.

DPM Energy, an independent party, has completed a preliminary study which estimates the electrical demand that will materialize from the DASP. This study suggests that load will begin to materialize in 2022 and could materialize up to: 103 MW by 2029, 180 MW by 2034, and 509 MW by 2051. This is equivalent to 8%, 14%, and 41% of the existing Downsview Area's Summer LTR of 1255 MW, as provided in Table 1. As a result, supplying the Downsview Lands with existing regional capacity will not be feasible without capacity investments.

[1] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

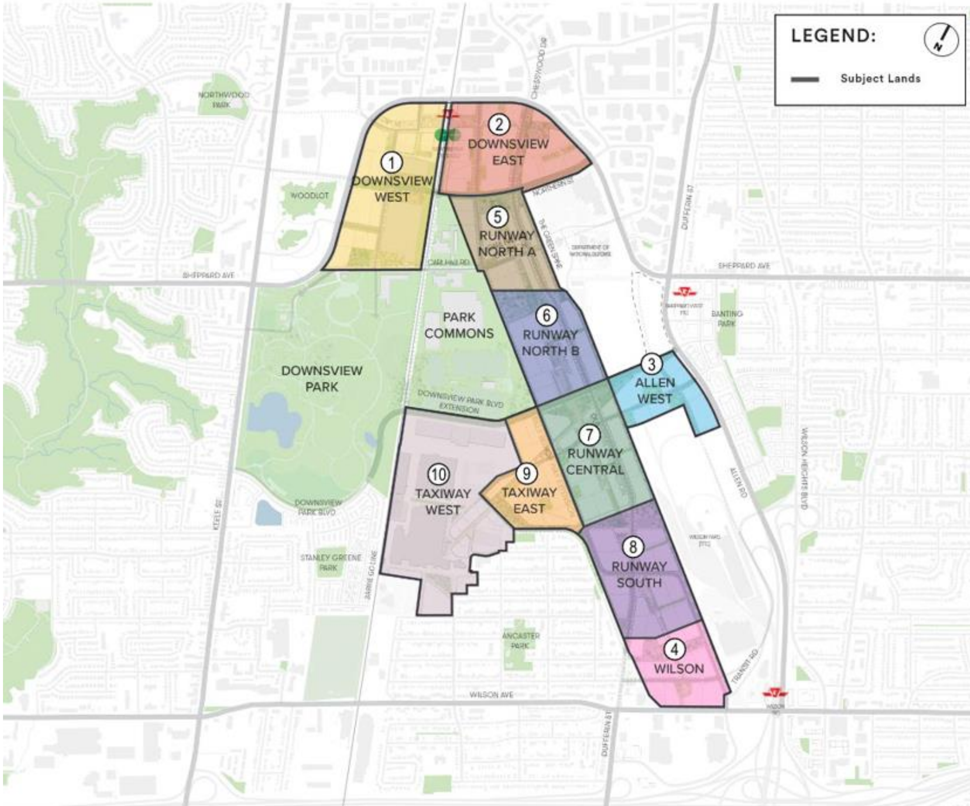


Figure 2 – Downsview Area Secondary Plan Map

2.3 Anticipated Future Loads

Toronto Hydro must ensure that its distribution system is capable of accommodating the anticipated load and generation growth in the City of Toronto. For the City of Toronto to achieve its TransformTO Net Zero Strategy targets, Toronto Hydro is anticipating the overall area load will grow by 40-70% over the next 20 years, largely due to the electrification of heating and transportation. As this transition occurs, Toronto Hydro must ensure that its distribution system is not a barrier to new customers looking to access its system, nor to existing customers looking to decarbonize.

Additionally, two existing large customers in the Downsview Area have approached Toronto Hydro to inquire about expanding their load by an additional 85 MW by 2030. These inquires have not been explicitly included in any forecasts. Although not yet firm requests, such inquiries corroborate the potential for the rapid load growth needed to achieve the TransformTO Net Zero Strategy targets, and the demand for capacity in the area.

Given the current highly-loaded state of the Downsview Area, the addition of the approved DASP, and the likelihood of rapid electrification underway, Toronto Hydro faces a large risk of either overloading its stations or of becoming a barrier to customers. Station loading can be managed in the short term, but medium and long-term solutions are needed to prepare for upcoming developments.

Options with several-year lead times (such as station expansion) must be considered far ahead of need to ensure that cost-effective solutions are pursued in a least-regret manner. Load relief plans for the Downsview Area should also consider the potential for future load growth, to ensure that investments are chosen to be cost-effective in the long term.

3 DOWNSVIEW AREA LOAD FORECAST – LOAD SENSITIVITY ANALYSIS

3.1 Peak Demand Forecast with Downsview Load

The Peak Demand Forecast only extends to 2031; however, as an additional approach to the sensitivity analysis, we will assume that the total Downsview Area load growth past 2031 is provided exclusively by the DASP. The NA forecast already includes consideration for the DASP up until 2031.

A preliminary study from DPM Energy estimates the electrical demand that will materialize from the Downsview Area Secondary plan. The annual load growth from this forecast over 2032-2051 was first adjusted to 70%[2], and then added to the 2031 station loads from the Peak Demand Forecast. The results are provided in Table 222, and referred to as the "25 Year Forecast" hereafter.

Table 2 - Estimated Station Loads under the 25 Year Forecast

Station	Summer LTR (MW)	2031	2034	2039	2044	2049	Year 100% Capacity is Reached
Bathurst TS	361	77%	81%	90%	99%	109%	2045
Fairbank TS	182	96%	101%	109%	118%	128%	2034
Fairchild TS	346	71%	71%	71%	71%	71%	N/A
Finch TS	366	99%	101%	105%	110%	115%	2032
Area Non-Coincident %	1255	85%	87%	92%	97%	103%	2046

/C

This forecast shows that by 2037, the Downsview Area as a whole will reach 90% loading, signaling a lack of capacity at the regional level. The forecast continues to show substantial load growth continuing past then, with no capacity remaining by 2046. Prior to that, 90% loading is forecasted at both Fairbank TS and Finch TS by 2031, and overloading by 2034. In summary, the 25 Year Forecast forecasts regional capacity constraints in the medium term, which worsen further into the long term.

3.2 Future Energy Scenarios

Depending on policy changes by all three levels of government, changes in customer preferences, and decarbonization efforts, there is a large range of outcomes which may impact Toronto Hydro's distribution system. To prepare for this range, Toronto Hydro commissioned the development of a long-term modelling tool known as Future Energy Scenarios or FES. The Future Energy Scenarios model projects what the demand would be under various policy, technology and consumer behaviour assumptions that are linked to the varying aspirations, goals, targets and constraints of decarbonizing the economy by 2040 or 2050.

[2] THESL's standard bus load forecasting methodology adjusts new customer load to 70% of the requested load in order to forecast bus load impacts.

Across the six modelled Future Energy Scenarios, Toronto Hydro expects that all but one station will become heavily loaded by 2035, and that the area as a whole will become overloaded between 2030 and 2037. Table 3 provides the station and area loading under the Future Energy Scenarios, and Figure 3 illustrates the area non-coincident loading under the Future Energy Scenarios. The Future Energy Scenarios do not specifically consider the DASP.

Table 3 – Non-Coincident Downsview Area Loading under Future Energy Scenarios

STATION	Summer LTR (MW)	2021	2024	2029	2034	2039	Year 100% Capacity is Reached[3]
Bathurst TS	361	67%	78-80%	82-89%	89-**101%**	95-**114%**	2034-N/A
Fairbank TS	182	**108%**	**114-117%**	**117-127%**	**124-142%**	**130-167%**	2021
Fairchild TS	346	62%	65-66%	67-72%	69-78%	70-84%	N/A
Finch TS	366	69%	**102-103%**	**109-116%**	**118-133%**	**124-150%**	2024
Area Non-Coincident %	**1255**	**72%**	**86-88%**	**91-98%**	**97-109%**	**102-122%**	2030-2037

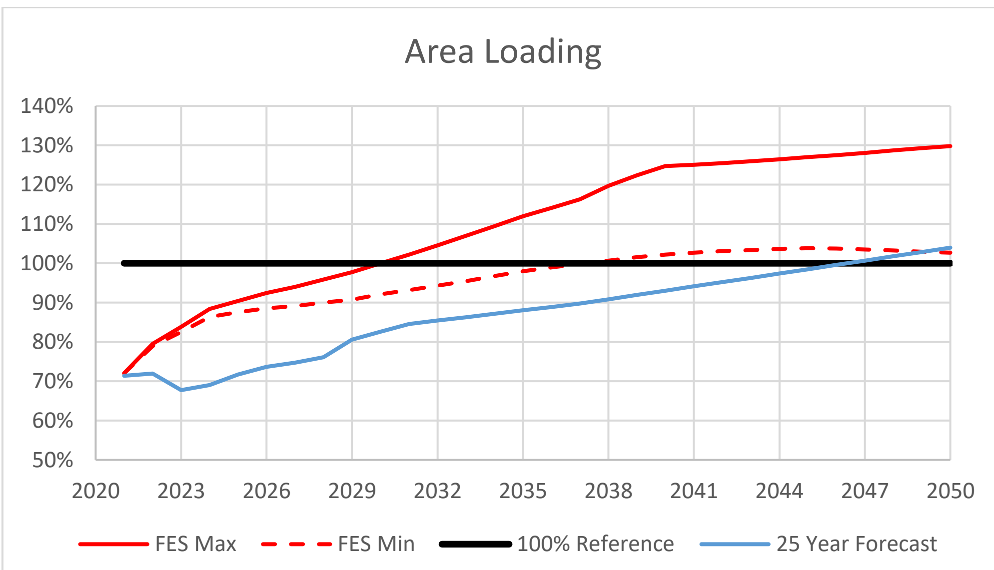


Figure 3 - Non-Coincident Downsview Area 20-Yr Loading from the Future Energy Scenarios Projections

3.3 Sensitivity Conclusions

Two approaches were considered to respectively assess loading impacts to the Downsview Area based on electrification, and the DASP. The first approach using the DASP shows regional constraints in the medium term, and the second FES approach shows regional constraints in the short term. This is marked

/C

[3] According to the Future Energy Scenarios output only. As a result, this year may be earlier than what is provided in the Peak Demand Forecast.

by overall Downsview Area loading reaching 90% or higher. Both approaches foresee regional loading increasing further past the 90% point to 100% or higher in the long term. /C

4 OPTIONS CONSIDERED

To address the needs of the Downsview Area, several options were considered, as outlined in the following subsections.

4.1 Option 1: Status Quo

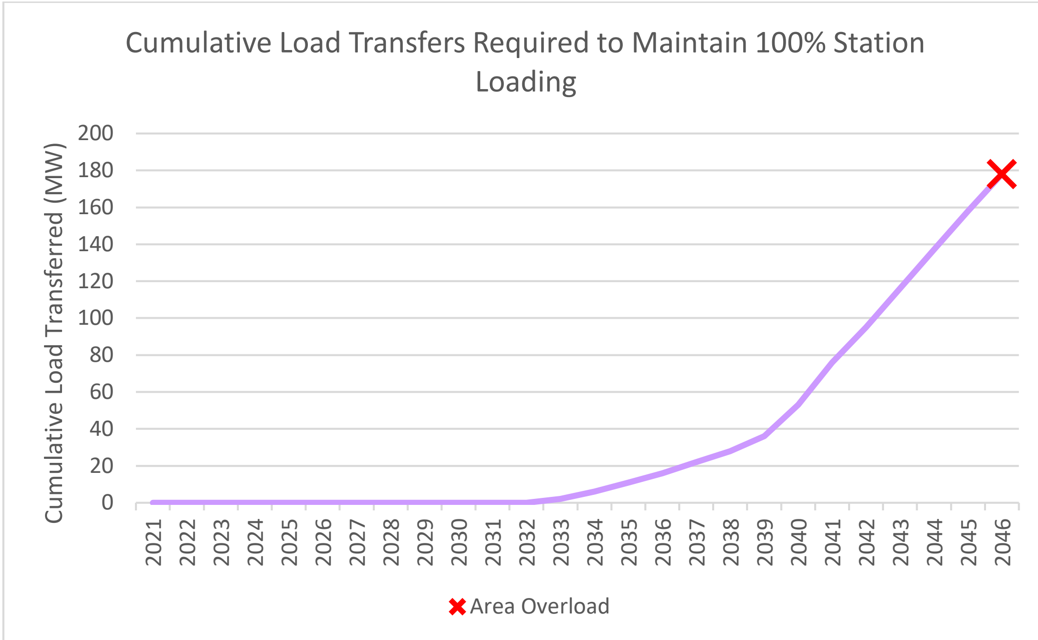
In practice, the Status Quo option is never recommended when capacity constraints are identified. But this option establishes the minimal level of intervention which is feasible, and illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress.

This option proposes to complete the minimal work needed, and only when immediately needed, in order to maintain station loading throughout the Downsview Area at or below 100%. Specifically, this Option assumes that load transfers will be completed just as each station reaches 100% loading, and only to the extent to keep the station at 100% loading. As a result, load transfer projects will need to be initiated and completed on an annual basis, and as a prerequisite for each new customer connection.

According to the Peak Demand Forecast in Table 111 in Section 2.1, the Downsview Area will not reach 100% loading over 2024-31, and therefore this option is possible. However, this option also presents large operational and reliability risks.

The 25 Year Forecast forecasts Finch TS and Fairbank TS to become highly loaded (90%) by 2029 and 2030 respectively. Once highly loaded, customer connections become challenging to accommodate in a timely manner, particularly large customer connections (28+ MVA). Further, connection costs charged to individual customers tend to increase, since pre-requisite load transfers are commonly needed to accommodate the new customers. By 2034, both stations are forecasted to become overloaded (100%), and offloading to Bathurst TS would be needed just to maintain the stations. /C

In this manner, the cumulative load transfers needed according to the 25 Year Forecast are shown in Figure 4. Over 2033-39 load transfers increase by approximately 5 MW annually, and then increase by approximately 20 MW annually until 2046. In total, 178 MW in load transfers would be needed over 2033-2046. After 2046, the Downsview Area is forecasted to be overloaded, and this option is no longer feasible.



/C

Figure 4 – Cumulative Load Transfers Required Over Time

The FES projections predict a much more rapid load growth, and by contrast load transfers would be needed over the 2024-2037 period. The FES projections predict that the Downsview Area will become overloaded by 2030-2037.

Aside from the cost impacts needed to complete the load transfers, there is also substantial operational risk involved in running stations at 100% load. The lack of capacity at Toronto Hydro's stations results in two negative impacts. First, it prevents new customers from connecting to the grid and burdens customers with higher connection costs. Second, it reduces the reliability of the station and may result in load shedding. These impacts would result in a detriment to Toronto Hydro's "Customer Focused" performance outcomes.

When a customer submits a connection request to a highly loaded station, Toronto Hydro must either offload the station by first completing a load transfer, or connect the customer to a station with capacity located further away. Both options results in higher costs and timelines for customers to connect. When multiple neighbouring stations are highly loaded, these options become even more limited, and connection costs and timelines increase further. Since these load transfers must be completed on-demand as needed and in highly loaded areas, this option carries substantial execution risk which is expected to further increase connection timelines. /C

If a single station asset is lost at a station whose load exceeds capacity, then Toronto Hydro would need to shed load[4] to avoid damaging the remaining assets. Consequently, a lack of station capacity results in reduced reliability at the station, which affects tens of thousands of customers and typically 100-300 MW of customer load per station. Because of the significant impacts to customer connections and reliability, this option is only considered as a short-term, interim solution.

In conclusion, this option is not a feasible solution. It requires a high level of risk to be maintained and managed for an unacceptably long period. /C

[4] Load Shedding is the process during which Toronto Hydro temporarily shuts down power supply to a limited number of customers, in order to reduce its station load below its station capacity. Power supply is restored to customers when doing so would no longer result in an overload. When needed, load shedding is generally rotated across customers for a few hours each, so that no customers experience long duration outages while others experience no outages at all.

4.2 Option 2: Load Transfers

The Load Transfer option presents what is needed to maintain station loading in a state which does not adversely affect daily operations nor incumber new customer connections, using existing station capacity.

This option proposes to complete load transfers on a planned basis, once at the start of each 5-year rate application period, to maintain station loading throughout the Downsview Area at or below 90% over the period. This is done while regional capacity remains, in order to free station capacity ahead of load growth and new customer connections. As a result, capacity constraints will not be felt during each period.

Given the 25 Year Forecast provided in Table 1112 of Section 3, the Downsview Area will reach 90% loading by 2037. Table 4 below shows that 14 MW in load transfers will be needed over the 2025-29 period, 76 MW will be needed over 2030-34, and following that the Area loading will surpass 90%. In total, 90 MW in load transfers would be required over 2025-2034 under this option.

Additionally, each FES Outlook estimates that the Downsview Area will exceed 90% loading by 2029. Therefore, this Option is only considered feasible up to 2034, with risk that this option may become infeasible by 2029.

Table 4 – Annual Load Transfers Required to Maintain Station Loading ≤ 90% /C

Annual Load Transferred (MW)		
2025-29	**2030-34**	**2035-39**
14	76	Above 90%

In conclusion, this option is not a feasible solution, since it can only be implemented up to 2034. To address needs in time for the 2035-2039 period, other options must be initiated in the 2025-2029 period.

4.3 Option 3: Non-Wires Solutions

This Option considers the possibility of addressing high loading and overloading within the Downsview Area using Non-Wires Solutions (”NWSs”), specifically the Flexibility Services segment. For further explanation on NWSs, please refer to the 2025-2029 Rate Application, E7.2 Non-Wires Solutions Program.

NWSs include the means to reduce the peak load of a targeted area, without increasing station capacity, and is designed to help address short-to-medium term capacity constraints. The Flexibility Services segment of the NWSs program includes local demand response (“LDR”).

LDR is able to reduce peak load through contracts with customers or aggregators to reduce their load during times of peak demand. As a result, the quantity of peak load which can be addressed is limited by the capability of customers to reduce their demand on Toronto Hydro’s distribution system. According to the 25 Year Forecast, 162 MW of LDR capacity would be needed by 2049 in order to maintain the Downsview Area loading at 90%. Such a large quantity of LDR capacity is unprecedented and is far beyond customer capability in the foreseeable future. For this reason, this option is not considered feasible as a long-term solution. /C /C

A key difference between LDR and other solutions, is that since it is a contracted service provided by customers or aggregators, LDR requires an annual cost. Therefore, as a long-term solution, it is possible for the cumulative LDR costs to exceed expansion costs. Similarly, because it is a contracted service, Toronto Hydro does not directly own any assets and faces operational and longevity risks due to dependency on third parties. For these reasons, LDR is best considered a short-to-medium term solution.

In conclusion, this option is expected to be able to address system needs in the short-to-medium term, but poses large long-term feasibility, operational, and financial risks.

4.4 Option 4: Station Upgrades

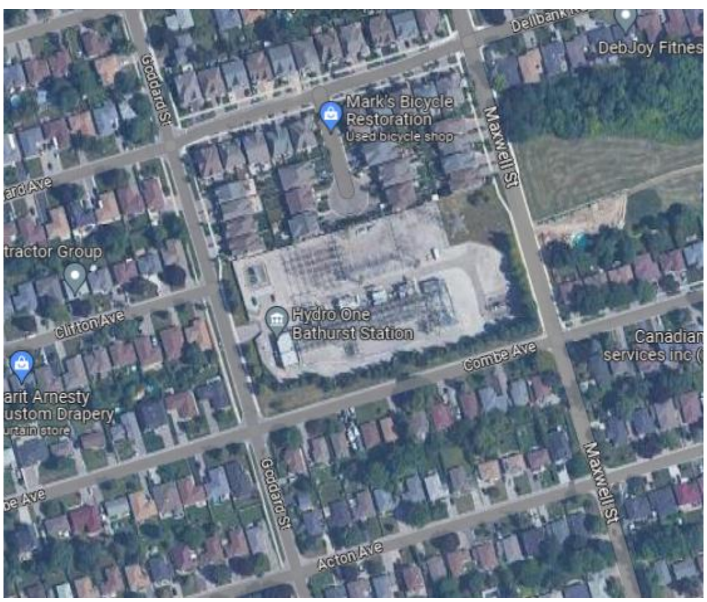
This option considers the possibility of expanding the capacity of existing DESNs in the Downsview Area by increasing the capacity of the limiting component(s) of the DESN. Such components may be: power transformers, secondary cables, circuit breakers, or buses. Generally, this allows for an incremental increase in station capacity.

All stations in the Downsview Area are already sized to their maximum ratings. Therefore, this option is not feasible.

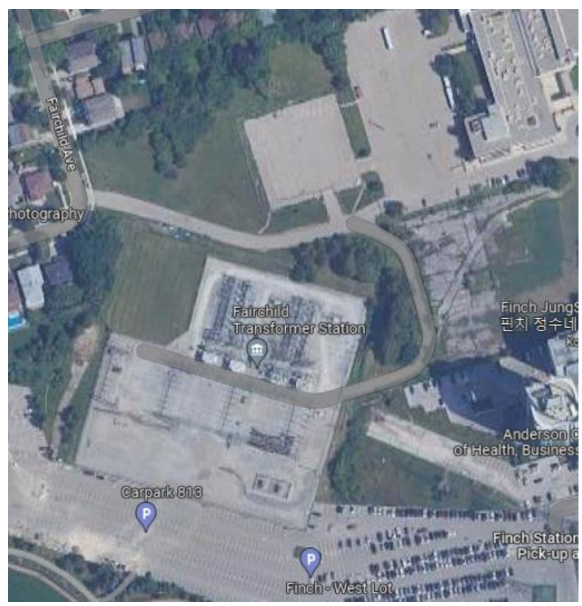
4.5 Option 5: New DESN(s)

This option considers adding one or more new DESNs at the existing stations in the Downsview Area, referred to as “station expansion”. A typical DESN provides 174 MW of new capacity and supplies 12 new feeders. This option provides the benefit of new capacity, but avoids the site procurement and transmission connection costs required of a new station.

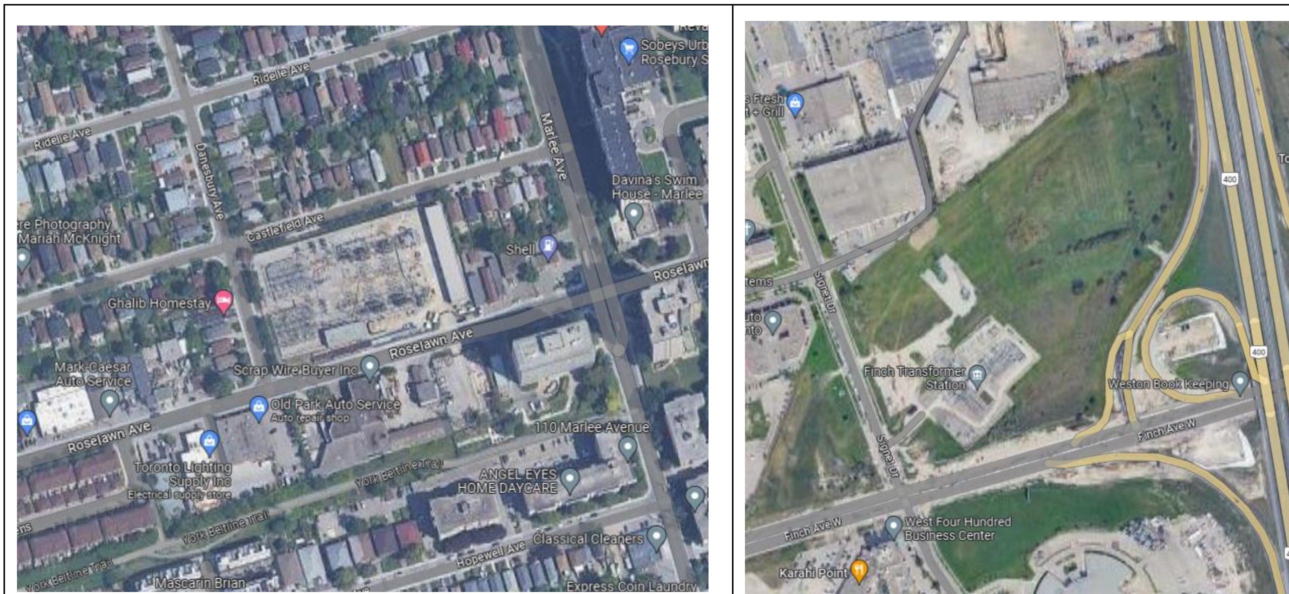
Of the four existing stations in the Downsview Area, only two have space surrounding the station which may potentially be considered for station expansion: Fairchild TS, and Finch TS. Bathurst TS and Fairbank TS are located in urban neighborhoods, surrounded by residential and small commercial buildings where expansion would not be feasible. Aerial views of the existing stations are provided in Figure 5 below.



Bathurst TS



Fairchild TS



Fairbank TS | Finch TS

Figure 5 – Aerial Overview of Existing Stations in the Downsview Area

Although some space may be available at Fairchild TS, expansion of this station is not well suited to meet the needs of the Downsview Area. First, the existing spare land would likely be insufficient to install a new DESN, and likely new land would need to be procured towards its north, east, or south, which presents feasibility challenges. Those challenges aside, the location of Fairchild TS is also far from Fairbank TS and Finch TS which need load relief, as can be seen in Figure 1 in Section 2. As a result, load relief would have to be achieved by cascading load transfers through Bathurst TS. Similarly, Fairchild TS is also located away from the DASP area, making it challenging to connect the new loads to new capacity which would be installed at Fairchild TS. Finally, Fairchild TS already supplies two DESN and egresses 24 feeders. Egressing another 12 feeders effectively from the same location would present a significant design challenge.

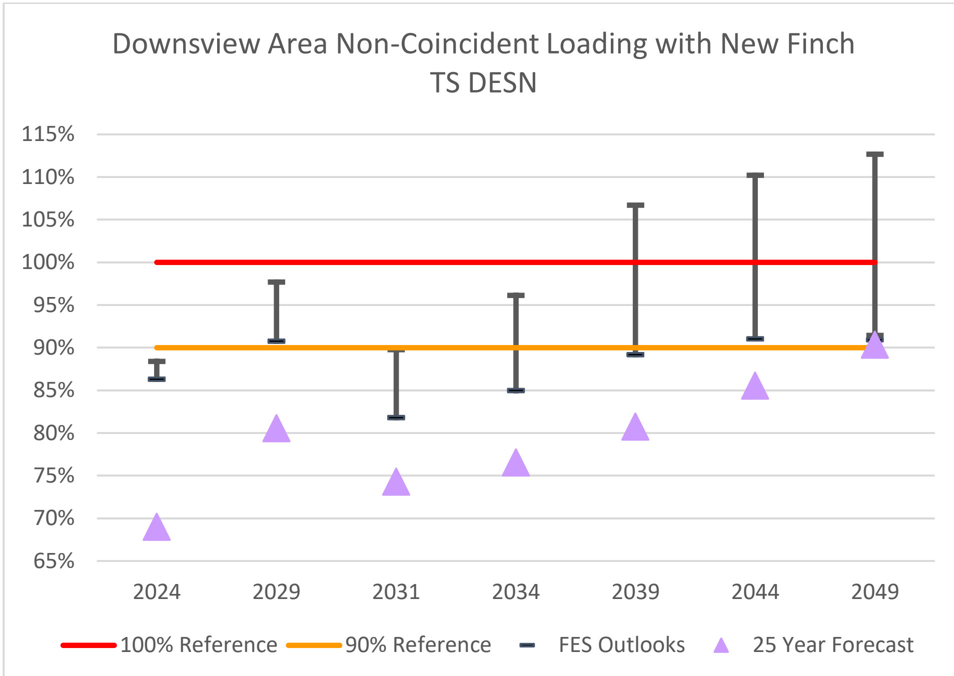
Finch TS has better land availability, and could likely accommodate another DESN, although it faces significant implementation challenges to be discussed later. Additionally, referring back to Figure 1 in Section 2, Finch TS could provide meaningful load relief to Bathurst TS, but not to Fairbank TS. Therefore, cascading load transfers[5] from Fairbank TS through Bathurst TS to Finch TS, would be needed to ultimately relieve Fairbank TS. This will ultimately magnify load transfer needs, discussed later and illustrated in Figure 888, reducing the efficacy of this option.

As a result of the above considerations, the expansion of Finch TS is the only technically feasible expansion option to consider, although it faces significant challenges in utilizing its new capacity. Therefore, the remainder of this option considers the impacts of an expansion only at Finch TS, and the risks involved.

Given a new DESN at Finch TS, Downsview Area loading is shown at 5-year intervals in Figure 666. Given the 25 Year Forecast, the addition of the new DESN will provide sufficient capacity until 2049. /C

[5] Cascading load transfer: When one station ("A") cannot directly offload to a neighbouring station ("B") with capacity, the station ("A") must instead first offload to an intermediate station ("C"). Following this, the intermediate station ("C") must transfer the same quantity of load to station ("B") which has the available capacity. Ultimately, station ("A") is offloaded by some amount, station ("B") increases in load by the same amount, and station ("C") experiences no change in load. This is process is called a cascading load transfer.

However, FES projections show that there is risk of Downsview Area overloading as early as 2036, and the magnitude of the potential overloading increases with time.



/C

Figure 6 – Downsview Area Loading with a New DESN at Finch TS

The scope of work involved is assumed to be completed entirely by Hydro One, with Hydro One owning all new assets. This is the standard for new Hydro One DESNs, which involve gas-insulated switchgear. Based on a similar expansion completed at Horner TS in 2022, the total cost in Hydro One Contributions is estimated to be $119 million with a project timeline of 6 years. The in-service date would therefore be Q1 2031. The annual estimated Hydro One Contributions are provided in Figure 7.

Because the 25 Year Forecast forecasts stations loading past 90% before the new DESN at Finch TS will /C be ready, this option assumes that the load transfers presented over 2025-29 in option 2 will be completed /C to manage station loading in the meantime. Once the DESN is ready in 2031, load transfers will again be needed to offload the existing stations onto the new DESN. /C Finally, although the new DESN will introduce capacity into the Downsview Area, it will not be situated to supply all new DASP load. As a result, load transfers will be needed again from 2035 onward in order to relieve Bathurst TS and/or Fairbank TS as they supply new DASP load. In total, 192 MW in load transfers are expected by 2049. The expected load transfers in 5-year increments are shown in Figure 888.

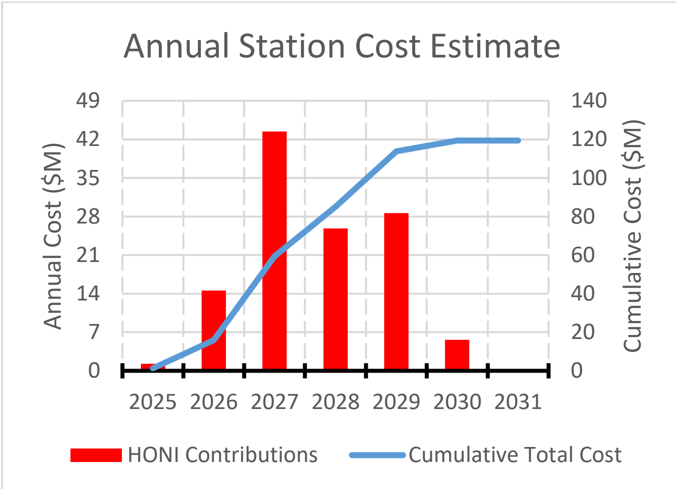


Figure 7 – Estimated Annual Hydro One Contributions for a new DESN at Finch TS

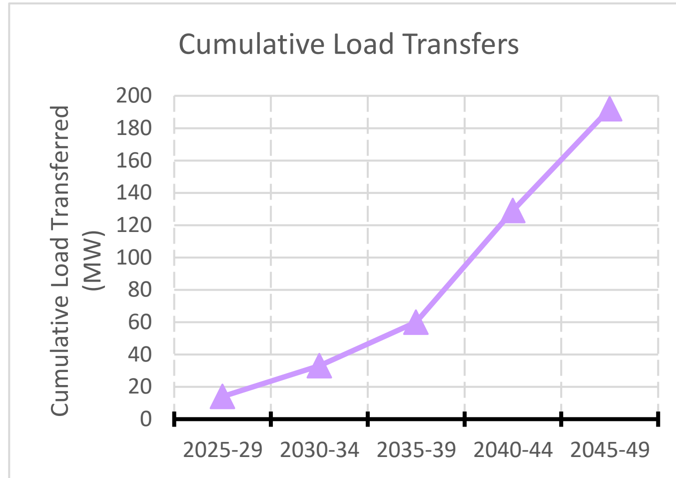


Figure 8 – Cumulative Load Transfers Required for a new DESN at Finch TS

/C

As an exercise intended to quantify the magnitude of load transfers needed, the above load transfer analysis does not consider the significant implementation challenges which are discussed below. Nonetheless, the analysis and Figure 888 show that an unprecedented load of 192 MW will need to be transferred over 25 years in order to make effective use of the new capacity installed in this option. Such a large level of needed load transfer to effectively utilize new capacity signals that the new capacity has been added in the wrong location within the Downsview Area. /C

In addition to the large magnitude of load transfers needed, a solution at Finch TS would encounter several significant implementation challenges which jeopardize the success of this option in the long term. First, Finch TS already supplies two DESNs and would face similar egressing challenges as Fairchild TS. Second, the DASP area is at the limit of the reach of Finch TS. Given the magnitude of the load expected from the DASP and the distance, reliability and voltage drop concerns would prevent Finch TS from supplying the entire DASP load. Finally, the geographical barriers of Highway 400 and the linear parks that already divide the Finch TS and Bathurst TS service territories would limit the number of feeders that could be extended from Finch TS eastward, effectively bottlenecking new capacity. These geographical barriers are shown in Figure 9 and Figure 10. /C

Figure 9 – Potential Location for New DESN at Finch TS

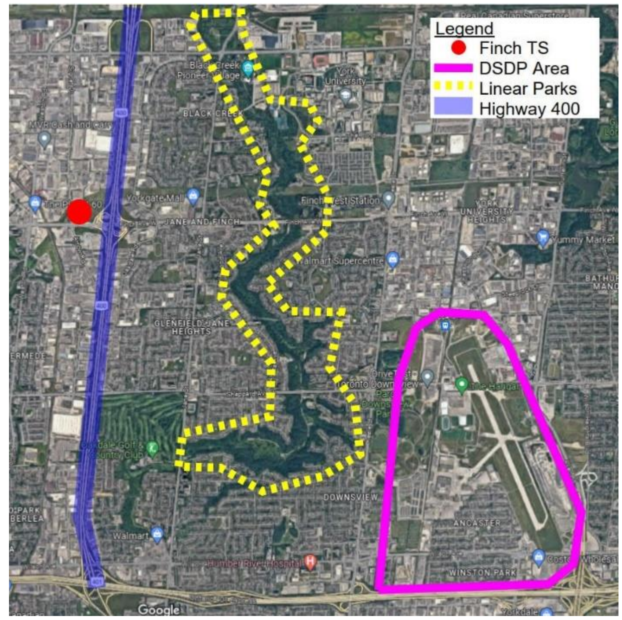


Figure 10 – Finch TS in Relation to the DSDP Area and Geographical Barriers

As a result of these implementation challenges and geographic barriers, there is a large risk that in the long term a significant portion of the new capacity installed at Finch TS will become stranded, while the adjacent Bathurst TS and Fairbank TS become overloaded. This risk is another signal that the new capacity has been incorrectly placed within the Downsview Area.

In addition to execution risk, this option carries a risk to cost which is expected to be even more likely to materialize. In order to overcome at least some of the challenges mentioned, and because of the high quantity of load transfers required, there is a high likelihood that the cost to complete the required load transfers will be significantly higher than average costs. Regarding the magnitude of load as being a driver of cost, this is because when large quantities of load are transferred, accompanying civil work such as new poles, duct banks, and/or cable chambers must be also be constructed.

In conclusion, the expansion of Finch TS is the only existing station in the Downsview Area which can accommodate an expansion. The expansion of Finch TS would introduce 174 MW of new capacity to the Downsview Area, and is expected to bring Downsview Area loading down to 90% until 2049. To achieve this outcome, an estimated $119 million in Hydro One Contributions is needed over 2025-2031, and an unprecedented 192 MW in load transfers is needed over 2025-2049. Because of congestion and geographical barriers, there is a high risk in achieving the total magnitude of load transfers required, which is expected to result in higher than average load transfer costs and stranding of the new capacity provided. The mentioned large risks and the need for an excess quantity of load transfers has motivated consideration of option 6, which seeks to add new capacity directly where it is needed.

/C

4.6 Option 6: New Station (“TS”)

This Option considers building a new transformer station within the Downsview Area, in order to bring new capacity to the area. Because the station will be newly constructed, it can be situated to facilitate the offloading of adjacent stations and/or the connection of new loads.

In particular, this Option proposes to build a new transformer station, named “Downsview TS”, within or on the border of the DASP area. Not only will this facilitate supply of the DASP loads directly, but the DASP area is also located in proximity to all stations in the Downsview Area requiring load relief: Bathurst TS, Fairbank TS, and Finch TS. Therefore, a new station in the DASP area will also be well placed for providing load relief. Similar to option 5, this option considers the installation of one new DESN providing 174 MW of new capacity and suppling 12 new feeders.

Given Downsview TS, the Downsview Area loading is shown at 5-year intervals in Figure 111111. Given the 25 Year Forecast, the addition of the new Downsview TS will provide sufficient capacity until 2049. However, FES projections show that there is risk of Area overloading as early as 2036, and the magnitude of the potential overloading increases with time. To mitigate the risk of overloading in the long term, Downsview SS (introduced below) is proposed to be constructed with the provision to install a second DESN in the future, if and when it is needed. /C

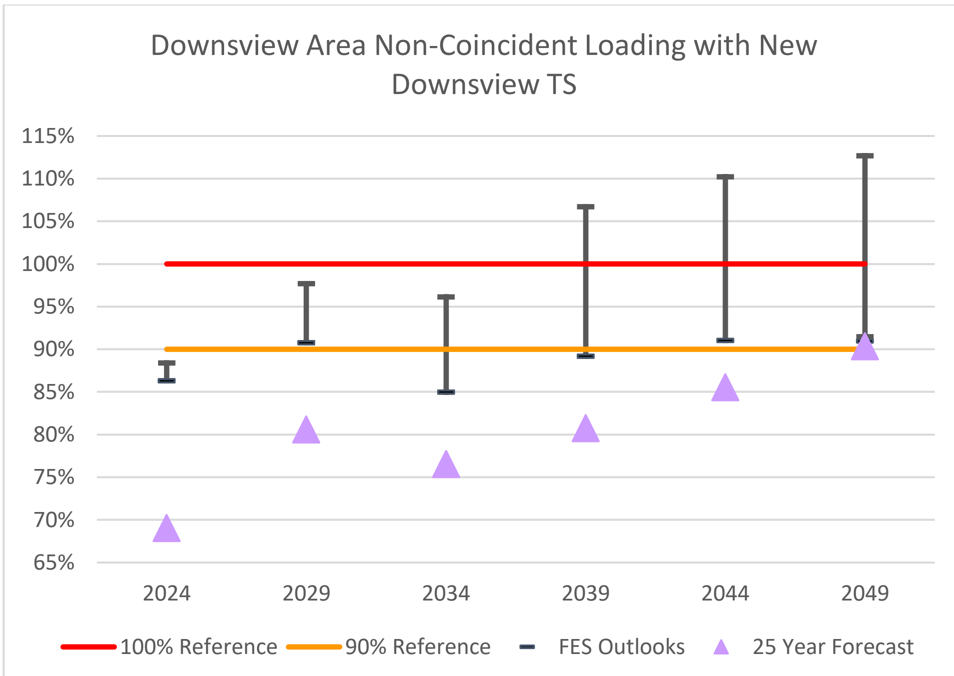


Figure 11 – Downsview Area Loading Following the Energization of Downsview TS

The scope of work of this option involves both a Hydro One and Toronto Hydro portion. The Hydro One portion includes the construction of a new switching station (“Downsview SS”) in the vicinity of the Hydro One right-of-way along Finch Ave W, which will serve as the supply and demarcation point for Toronto Hydro’s new Downsview TS. The Toronto Hydro portion of work will include the procurement of land for Downsview TS and the construction of: 230 kV underground cables and duct banks from Downsview SS to Downsview TS, a new station building, two primary circuit breakers and transformers, and one switchgear. Because of the large scope of work, Downsview TS’s in-service date is estimated to be Q4 2033, assuming it begins in Q1 2025.

Based on estimates of the costs for each major asset installed, and an estimated schedule of the project, an annual cost estimate was developed and is shown in Figure 11. The total cost over 2025-2033 is estimated to be $170 million, excluding inflation assumptions, comprising of $118 million in Toronto Hydro costs and $52 million in Hydro One Contributions.

Because the 25 Year Forecast forecasts stations loading past 90% before Downsview TS will be ready, this option assumes that the load will be completed over 2025-2033 to manage station loading in the meantime. Once Downsview TS is ready in 2034, load transfers will be completed to offload the existing stations. Because Downsview TS will be located in the vicinity of the DASP area, it will be able to directly supply the new loads without additional load transfers. As a result, no significant load transfers are /C anticipated until the Downsview Area loading is forecasted to reach 90% again in 2045. The expected load transfers in 5-year increments are shown in Figure 12.

In total, 55 MW in load transfers are expected by 2044, and 142 MW are expected by 2049. Load transfers increase in 2045 to prevent overloading at Downsview TS. An alternative to these subsequent load transfers is to install a second DESN at Downsview TS, whose provision will be included as part of this option.

/C

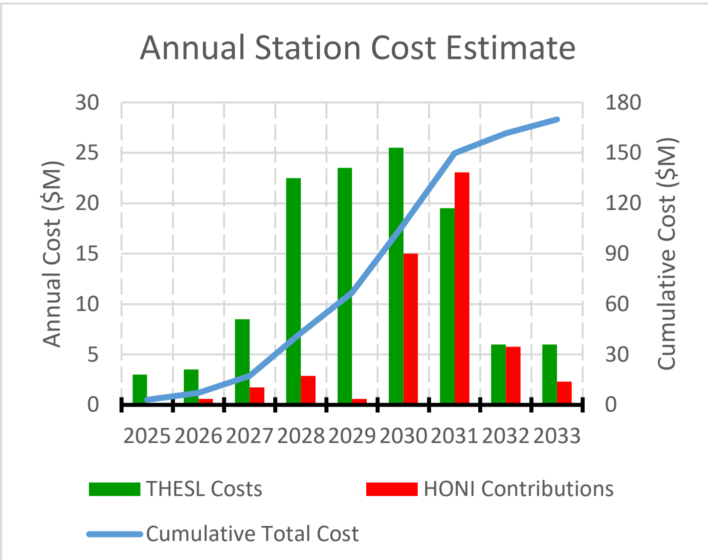


Figure 12 – Estimated Annual Expenditures for Downsview TS[6]

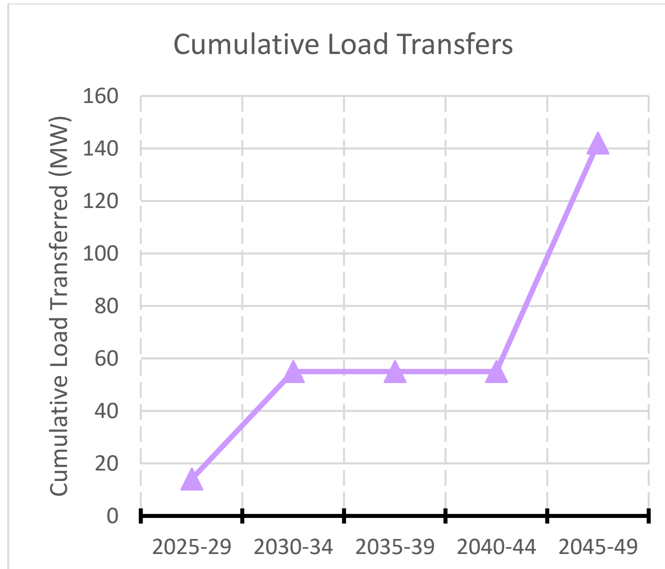


Figure 13 – Cumulative Load Transfers Required for Downsview TS

In conclusion, this option presents a feasible solution by constructing a new Downsview TS and introducing 174 MW of new capacity to the Downsview Area. This investment is expected to bring the Downsview Area loading down to 90% until 2049. To achieve this option, an estimated $170 M[6] of expansion work is needed over 2025-2033, and an estimated 142 MW in load transfers is needed over 2024-2049. This option will also include the provision to install a second DESN in the future; which if pursued in 2044, would reduce the load transfer investment from 142 MW to 55 MW.

/C

[6] Excluding inflation assumptions

5 OPTION ANALYSIS AND RECOMMENDATION

The key results of the options studied are summarized in Table 554. Options were considered in order of increasing level of intervention, until an acceptable option was identified. This ultimately led to the identification of the proposed option, Option 6 – New TS, as the only option capable of meeting system needs with reasonable risks. /C

Table 5 – Summary of Options

Option (Increasing in Level of Intervention)	Decision	Reason for Decision	Decision Criteria				
			Acceptable Long Term Solution	Cumulative Load Transfers or NWSs Required [by 2044/2049] (MW)	Operational + Customer Connection Risks	Execution Risk	Risk of Subsequent Overloading
1 – Status Quo	Reject	This Option is only viable as a short-term solution.	No	N/A – viable only for a short term	High	Medium	Forecasted Overload
2 – Load Transfers	Reject	This Option can only manage loading until 2034.	No	N/A – viable only for medium term	Low	Minimal	Forecasted Overload
3 – NWSs	Reject	NWSs are not designed to be long term solutions. Very high execution risk due to unprecedented quantity of NWSs needed.	No	93/162	High	Very High	Mitigated
4 – Station Upgrades	Reject	Technically infeasible: Station equipment is already sized to maximum ratings.	No	N/A	N/A	N/A	N/A
5 – New DESN(s)	Reject	High execution risks, likelihood of stranded capacity, and excessive quantity of load transfers drive the need for an alternative solution.	Yes	129/192	Minimal	High	Unmitigated
6 – New TS	**Accept**	Meets system needs with reasonable risks.	Yes	55/142	Minimal	Medium	Mitigated

/C

/C

Option 1 – Status Quo, as mentioned in Section 4.1, is never recommended when capacity constraints are identified, but illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress. Since this option is only viable in the short term, it was rejected. Similarly, the analysis for Option 2 – Load Transfers showed that the Option is only viable up until 2034, and as a result /C it was also rejected.

Option 3 – NWSs would be required indefinitely and would require an unprecedented quantity of load to /C be addressed, 162 MW by 2049. As mentioned in Non-Wires Solutions Program Narrative E7.2.1.1, NWSs are "designed to help address short-to-medium term capacity constraints", and are not designed to be long term solutions. Moreover, Toronto Hydro's NWSs over 2015-2019 have targeted a maximum of 10 MW, and the Program over 2025-2029 proposes a maximum target of 30 MW (see E7.2.1.4). As a result, a target of 162 MW by 2049 is highly unprecedented which translates into a very high execution /C risk. Therefore, because it is not designed to be a long-term solution and its very high execution risk, this option was rejected.

Option 4 – Station Upgrades was considered, but all station equipment in the Downsview Area is already sized to maximum ratings and cannot be further upgraded. Therefore, this option is technically unfeasible and was rejected.

Option 5 – New DESN(s) was considered for each of the 4 existing stations within the Downsview Area; but as mentioned in Section 4.5, only Finch TS could accommodate a new DESN. Although possible, a new DESN at Finch TS would be especially difficult to utilize effectively in the Downsview Area, due to: existing congestion, geographic barriers, and distance from the DASP area. These challenges translate into high execution risks, an expectation of stranded capacity at Finch TS (inaccessible to the rest of the Downsview Area), and an expectation for higher than typical load transfer costs. Finally, because Finch TS is remote from the DASP area and is not central to the broader Downsview Area, this option is forecasted to require a remarkably high quantity of load transfers: 129 MW by 2044 and 192 MW by 2049. These load transfers would be needed to redistribute the new capacity across the Downsview Area. /C As a result of the many significant risks, challenges, and inefficiencies presented by this option, this option was ultimately rejected.

Motivated by the challenges encountered in its analysis of option 5, Toronto Hydro next considered installing new capacity both within the DASP area where new capacity is needed most, and in a central location within the broader Downsview Area to facilitate relief of the existing stations. This resulted in Option 6 – New TS which specifically considers installing a new TS within the DASP area, and whose details are reviewed next.

Because of the proposed placement of the new TS, it is suited to offload existing stations and directly supply the new DASP loads, which is the major driver of load growth in the broader Downsview Area. This results in a minimal execution risk in terms of addressing system needs once the new TS is in service. However, the construction of a new TS is a long and complicated project; and therefore, overall execution risk was evaluated as Medium. Because of the designed placement of the new TS, the required load transfers of this option are less than in the previous option 5 at: 55 MW by 2044 and 142 MW by /C 2049.

Option 6 also includes a provision to address the risk of subsequent overloading in the long term (illustrated in Figure 111111), by permitting a second DESN to be installed at the newly constructed TS, whereas no such provision exists in option 5. Moreover, if the second DESN is constructed by 2044, then /C the required load transfers of this option can be limited to 55 MW, rather than 142 MW by 2049. This is because the load transfers in 2045-2049 are needed solely to relieve Downsview TS.

In light of the multiple benefits of Option 6 – New TS shown over Option 5 – New DESN(s), and given the multiple significant drawbacks of Option 5, Toronto Hydro selected Option 6 – New TS as the only reasonable solution to address capacity needs within the Downsview Area. Toronto Hydro proposes to implement option 6 with its Downsview TS Project included in its 2025-2029 rate application, E7.4 Stations Expansion Program.

6 CONCLUSION

Toronto Hydro has identified a need for additional capacity within the Downsview Area due to forecasted high station loading in the medium term, and forecasted Area overloading in the long term from the Downsview Area Secondary Plan ("DASP").

To address this need, Toronto Hydro has considered multiple options including: Status Quo, Load Transfers, NWSs, Station Upgrades, New DESN(s), and New TS.

When considering short-to-long term needs, project costs, risks, and secondary benefits, Toronto Hydro concluded that its Option 6 – New TS is the only reasonable option which addresses system needs.

The recommended option will construct a new TS, Downsview TS, which will provide 174 MW of new capacity to the Downsview Area, with forecasted energization in Q4 2033. The proposed location of Downsview TS is in proximity to the lands of the DASP, and also central to the Downsview Area. This will permit it both to directly supply new DASP loads, and relieve the highly loaded Bathurst TS, Fairbank TS, and Finch TS.

The cost to construct the new TS is estimated to be $76.0 million over the 2025-2029 period and $116.2 million over the 2030-2034 period, including Hydro One contributions and inflation assumptions. Only $14.6 million of the project's estimated cost is planned to be capitalized in the 2025-2029 period. These costs are related to the completion of site acquisition and preparation, and the completion of civil construction. The remaining project costs will be capitalized at the completion of the project once the station has been energized.

Because of the long construction timeline, load transfers and/or NWSs will be needed in parallel with construction of the new TS. An estimated 14 MW in load transfers or NWS capacity will be needed by 2029, and a subsequent 41 MW will be needed between 2030-2034. /C

Downsview TS will be constructed with a provision to install an additional 174 MW of capacity if and when needed in the future. This will address the risk of subsequent high loading or overloading, and can eliminate the need for subsequent load transfers after 2034. /C

The proposed investments will address upcoming high loading in the Downsview Area, support the City of Toronto's Downsview Area Secondary Plan, and prepare the Downsview Area to support electrification over the next 25 years. /C