Hydro One Networks Inc.
483 Bay Street
7th Floor South Tower
Toronto, Ontario M5G 2P5
HydroOne.com

Elise Andrey
Director, Applications Delivery
C 416.770.6305
Elise.Andrey@HydroOne.com

BY EMAIL

December 30, 2025

Mr. Ritchie Murray
Acting Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Mr. Murray,

EB-2021-0110 – Hydro One Networks Inc.'s Settlement Commitments

In Hydro One Networks Inc.'s (Hydro One) application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached a settlement with all parties (the Settlement Proposal) which was approved by the OEB on November 29, 2022.

Under the terms of the Settlement Agreement, Hydro One agreed to prepare and publish reports listed in Appendix A below. Accordingly, these materials for 2024 have been published on Hydro One's website: Transmission Rate Applications, Distribution Rate Applications.

Sincerely,

Elise Andrey

Appendix A

Section	Description	Settlement Reference[1]
1.0	Scorecards	
1.1	Fiscal 2024 - Hydro One Networks Distribution Scorecard and Management Discussion and Analysis	Part A.2
1.2	Fiscal 2024 - Hydro One Networks Electricity Transmitter Scorecard and Management Discussion and Analysis	Part A.2
2.0	Capital Performance Reports	
2.1	2024 Transmission Capital Performance Report	Part A.1
2.2	2024 Distribution Capital Performance Report	Part A.1
2.3	2024 General Plant Capital Performance Report	Part A.1
3.0	Other Reporting	
3.1	DERs Connected to Hydro One's Distribution System (per undertaking JT-3.22)	Part A.3
3.2	Residential Energy Storage Performance Data	Part E.3
3.3	Grid Scale Energy Storage Performance Data	Part E.3

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.327-334 (Settlement Proposal, Appendix A, p. 106-113)

Section 1.1

Fiscal 2024 – Hydro One Networks Distribution OEB Scorecard and Management Discussion and Analysis

Fiscal 2024 – Hydro One Networks Distribution OEB Scorecard, Management Discussion and Analysis (“Scorecard MD&A”)

Hydro One Networks Distribution OEB Scorecard MD&A - General Overview

In Hydro One Networks Inc.’s (Hydro One) application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached settlement with all parties (the Settlement Agreement) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, Hydro One agreed as follows:

> *For each of Distribution and Transmission, Hydro One will prepare a scorecard. The scorecards will be prepared subject to the following conditions: i) they will be prepared annually, no earlier than September 30th each year to align with OEB RRR scorecards; ii) upon completion they will be published on Hydro One’s website; iii) they will be prepared for the purposes of Hydro One’s next Distribution and Transmission rebasing application and will not form part of Hydro One’s annual update applications during the 2023-2027 Custom IR term; iv) they will include discussion sections similar to the OEB Distribution RRR Scorecard; and v) they may be redacted if necessary.*[1]

The Hydro One 2024 Distribution Scorecard is attached and the discussion is set out below.

Customer Satisfaction

Hydro One collects customer satisfaction data through customer perception studies conducted by independent expert research firms.

- **Small Business and Residential Satisfaction**

  The Small Business and Residential (“SB&R”) customer satisfaction survey is conducted every month among randomly selected customers who may or may not have interacted with Hydro One recently. The customer satisfaction measure captures SB&R customers’ overall satisfaction with the service they receive from Hydro One. The survey includes a range of questions regarding customers’ experience and satisfaction with their electricity service, allowing Hydro One to monitor how well the company meets customers’ expectations and delivers on critical success factors.

  The SB&R Satisfaction was 88% in 2024, which was better than the target of 87%.

[1] EB-2021-0110, Settlement Agreement, Appendix A

- **Handling of Unplanned Outages Satisfaction**

  This measure captures customer satisfaction with Hydro One's handling of unplanned outages. The data is collected through a transactional online survey that is sent to customers who reside in an area affected by an unplanned outage, after the outage has occurred. An outage satisfaction index is calculated as the simple average of three components: (1) satisfaction with communication, (2) satisfaction with time it took to restore power and (3) satisfaction with accuracy of Estimated Time of Restoration (ETR).

  The Handling of Unplanned Outages Satisfaction was 79% in 2024, which was less than the target of 81%. This result was attributable to lower overall satisfaction with Hydro One's communication during outages.

- **Call Centre Customer Satisfaction**

  This measure captures customer satisfaction with services provided by Hydro One's call centre, which is often the first point of contact Hydro One has with a customer when they have a question or an issue that needs to be resolved. Customer satisfaction after the call is a strong indication of whether or not a customer inquiry has been addressed appropriately. This metric demonstrates whether or not services are being provided in a manner that is responsive to customer needs. The call centre customer satisfaction survey occurs shortly after the phone call, which allows the call centre to capture timely and accurate information and to address any areas for improvement.

  The Call Centre Customer Satisfaction was 86% in 2024, which met the target of 86%.

- **myAccount Customer Satisfaction**

  This measure captures customer satisfaction with services delivered by Hydro One's myAccount web portal. The myAccount portal allows customers to view their bills, analyze their electricity usage and request several services online, in a convenient and efficient manner.

  The myAccount Customer Satisfaction was 72% in 2024, which was better than the target of 67%.

Cost Control

- **Pole Replacement - Gross Cost per Unit**

  The Pole Replacement Gross Cost per Unit is defined as the total pole replacement costs, divided by the total number of poles replaced.

  The gross cost per pole replacement was $19,477 in 2024, which was higher than the target of $10,818. This result is due to carry-over costs from the previous year, higher material and contractor costs, and a higher volume of more complex and labour-intensive poles being completed.

- **Vegetation Management – Gross Defect Correction Cost per km**

  The Vegetation Management Gross Defect Correction Cost per kilometer is measured as the total cost of the Optimal Cycle Protocol vegetation management program divided by the number of kilometers of line cleared.

  The Vegetation Management unit cost was $8,026 in 2024, which was higher than the target of $3,901. This result is due to increased defect densities and higher labour costs.

- **Station Refurbishment – Gross Cost per MVA**

  The Station Refurbishment – Gross Cost per Mega Volt Amp ("MVA") is defined as the total cost of station refurbishments divided by the total number of refurbished MVAs. Every station refurbishment project has a unique scope of work resulting in variation of the total cost for each investment. The cost per MVA measure only considers projects which have a station MVA of less than 10 MVA.

  The Station Refurbishment cost was $818,524 per MVA in 2024, which was higher than the target of $423,000 per MVA. This result was attributable to increased material costs.

- **Operations, Maintenance and Administration (OM&A) dollars per customer**

  OM&A dollars per customer is defined as total OM&A divided by the number of customers.

  The OM&A per customer was $474 in 2024, which was higher than the target of $418. This reflects higher emergency restoration costs and demand driven work, and higher spending on information technology initiatives.

- **OM&A dollars per kilometer of line**

  OM&A dollars per kilometer of line is defined as total OM&A divided by the total number of kilometers of distribution lines.

  The OM&A per kilometer of line was $5,709 in 2024, which was higher than the target of $4,838. This reflects higher emergency restoration costs and demand driven work, and higher spending on information technology initiatives.

System Reliability

The System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) are tracked for a number of scenarios.

- **SAIDI for Equipment-Caused Interruptions**

  SAIDI for Equipment-Caused Interruptions is defined as the average number of hours that power to a customer is interrupted for equipment-caused interruptions. This metric tracks the SAIDI impact and outcome caused by distribution equipment failures on an annual basis.

  The SAIDI for Equipment Caused Interruptions was 1.7 hours in 2024, which was slightly higher than the target of 1.6 hours.

- **SAIDI for Vegetation-Caused Interruptions**

  SAIDI for Vegetation-Caused Interruptions is defined as the average number of hours that power to a customer is interrupted for vegetation-caused interruptions. This metric tracks the SAIDI impact and outcome for vegetation-caused interruptions on an annual basis. Visibility to the vegetation-caused interruptions allows focus to be placed on those areas with less-than-optimal performance. Ultimately, one of the expected outcomes and customer benefits of the vegetation management program is a reduction in vegetation-caused outages. This metric is a lagging indicator of the outcomes of the vegetation management program.

  The Vegetation Caused SAIDI was 2.0 hours in 2024, which was higher than the target of 1.7 hours. This result is due to increased storm days in 2024, including 48 storm days compared to the 10-year historical average of 34 storm days per year.

- **SAIDI – Rural Duration**

  SAIDI – Rural Duration is defined as the total number of hours of interruption for rural customers divided by the total number of rural customers served. All rural planned and unplanned interruptions of one minute or more (excluding Loss of Supply and Force Majeure Events) are used to calculate this measure.

  The SAIDI – Rural Duration was 9.2 hours in 2024, which was higher than the target of 4.8 hours. This result is due to increased storm days in 2024, including 48 storm days compared to the 10-year historical average of 34 storm days per year.

- **SAIFI - Rural Frequency of Outages**

  SAIFI – Rural Frequency of Outages is defined as the total number of rural customer interruptions divided by the total number of rural customers served. The SAIFI-Rural metric tracks the average interruption frequency for the rural areas only. All rural planned and unplanned interruptions of one minute or more (excluding Loss of Supply and Force Majeure Events) are used to calculate this measure.

  The SAIFI - Rural Frequency of Outages had a frequency of 3.1 outages per rural customer in 2024, which was higher than the target of 2.1 outages per rural customer. This result is due to increased storm days in 2024, including 48 storm days compared to the 10-year historical average of 34 storm days per year.

- **SAIDI – Urban Duration**

  SAIDI – Urban Duration of outages is defined as the total customer hours of interruption for urban customers divided by the total number of urban customers served.

  The SAIDI - Urban Duration was 3.1 hours in 2024, which was higher than the target of 2.8 hours. This result is due to increased storm days in 2024, including 48 storm days compared to the 10-year historical average of 34 storm days per year.

- **SAIFI - Urban Frequency of Outages**

SAIFI – Urban Frequency of Outages is defined as the total number of interruptions for urban customers divided by the total number of urban customers served. The SAIFI – Urban metric tracks the average interruption frequency for the urban areas only.

The SAIFI - Urban Frequency of Outages had a frequency of 1.5 outages per urban customer in 2024, which met the target of 1.5.

- **Large Customer Interruption Frequency**

  Large Customer Interruptions Frequency is defined as the total number of interruptions for Large Distribution Customer Accounts ("LDAs") divided by the total number of large distribution accounts served. This metric tracks the sustained interruption frequency to all LDA customers connected to Hydro One.

  The Large Customer Interruption Frequency had a frequency of 1.3 interruptions per large distribution customer account in 2024, which was better than the target of 1.6 interruptions per large distribution customer account.

Note to Readers of Fiscal 2024 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance.

Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "can", "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements and information. Such statements include, but are not limited to, references to the collection of customer satisfaction data, and the data's scope and uses; expected timing of customer perception studies; the means by which customers interact with Hydro One; system reliability measures and expected outcomes of implementation; and targets. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Some of the factors that could cause such differences include the scope, duration, and impacts of infectious diseases, including the COVID-19 pandemic and related developments including government and the company's response and mitigation measures, legislative or regulatory developments, government policy and program developments, an unexpected increase in call centre volumes, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgment on the reporting date of the performance scorecard and could be markedly different in the future. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

Hydro One Networks Distribution OEB Scorecard

Performance Outcomes	Performance Categories	Measures	2019	2020	2021	2022	2023	Actual 2024	JRAP Target 2024
			Year End Results						
Customer Focus	Customer Satisfaction	Small Business and Residential Satisfaction (%)	86%	87%	89%	87%	87%	88%	87%
		Handling of Unplanned Outages Satisfaction (%)	78%	77%	78%	78%	78%	79%	81%
		Call Centre Customer Satisfaction (%)	90%	86%	86%	86%	84%	86%	86%
		My Account Customer Satisfaction (%)	72%	52%	60%	67%	68%	72%	67%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in ($)	$12,499	$10,624	$11,158	$13,133	$15,216	$19,477	$10,818
		Vegetation Management - Gross Defect Correction (OCP) Cost per km ($)	$5,609	$5,670	$4,019	$5,070	$6,996	$8,026	$3,901
		Station Refurbishment - Gross Cost Per MVA ($)	$512,000	$315,000	$356,899	$655,244	No projects in service	$818,524	$423,000
		OM&A dollars per customer ($)	$415	$410	$409	$461	$459	$474	$418
		OM&A dollars per km of line ($)	$4,644	$4,622	$4,779	$5,441	$5,469	$5,709	$4,838
	System Reliability	SAIDI for Equipment Caused Interruptions (hrs)	2.5	2.3	2.1	2.6	2.0	1.7	1.6
		SAIDI for Vegetation Caused Interruptions (hrs)	2.4	3.1	2.7	2.5	1.7	2.0	1.7
		SAIDI - Rural - duration (hrs)	7.9	8.3	7.5	8.0	8.8	9.2	4.8
		SAIFI - Rural - frequency of outages	2.7	2.8	2.6	2.8	3.2	3.1	2.1
		SAIDI - Urban - duration (hrs)	3.2	2.7	2.8	2.8	3.5	3.1	2.8
		SAIFI - Urban - frequency of outages	1.5	1.3	1.4	1.3	1.6	1.5	1.5
		Large Customer Interruption Frequency (LDA's) - Interruptions per LDA	1.5	1.6	1.3	1.5	1.7	1.3	1.6

Section 1.2

Fiscal 2024 – Hydro One Networks Electricity Transmitter Scorecard and Management Discussion and Analysis

Fiscal 2024 Hydro One Networks Electricity Transmitter Scorecard, Management Discussion and Analysis (“Scorecard MD&A”)

Hydro One Networks Electricity Transmitter Scorecard MD&A - General Overview

In Hydro One Networks Inc.’s (Hydro One) application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached settlement with all parties (the Settlement Agreement) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, Hydro One agreed as follows:

> *For each of Distribution and Transmission, Hydro One will prepare a scorecard. The scorecards will be prepared subject to the following conditions: i) they will be prepared annually, no earlier than September 30th each year to align with OEB RRR scorecards; ii) upon completion they will be published on Hydro One’s website; iii) they will be prepared for the purposes of Hydro One’s next Distribution and Transmission rebasing application and will not form part of Hydro One’s annual update applications during the 2023-2027 Custom IR term; iv) they will include discussion sections similar to the OEB Distribution RRR Scorecard; and v) they may be redacted if necessary.*[1]

The Hydro 2024 One Transmission Scorecard is attached, and the discussion is set out below.

Service Quality

- **Customer Delivery Point Performance - Standard Outliers as Percent of Total Delivery Points**

  The Customer Delivery Point Performance is a service quality metric that is measured as the number of standard performance outliers (using standards set by the OEB) as a percentage of the total number of Hydro One delivery points. Customer Delivery Point Performance Standards (CDPPS) were established by the OEB to ensure acceptable transmission reliability experienced at transmission customer delivery points. The group outlier standard defines a delivery point as an outlier if its performance is over the thresholds based on its station load size. The individual outlier standard defines a delivery point as an outlier if its recent two-year’s performance is worse than its historical performance. The percentage of outliers to total number of delivery points is measured annually.

  The Standard Outliers as a Percent of Total Delivery Points was 13.6% in 2024, which was higher than the target of 10.8%. The GTA

[1] EB-2021-0110, Settlement Agreement, Appendix A

flooding event impacting Manby TS in July of 2024 was a major contributor to the overall result.

Customer Satisfaction

- **Overall Customer Satisfaction**

  This measure reflects the overall satisfaction levels among customers within the three major transmission-connected segments (Transmission End Users, Local Distribution Companies (LDCs) and Transmission-Connected Generators).

  The Overall Customer Satisfaction was 85% in 2024, which was lower than the target of 88%. The result was attributable to an increase in major weather events causing system outages.

- **Satisfaction With Outage Planning Procedures**

  This measure reflects the satisfaction with planned outage management among customers within the three major transmission-connected segments (Transmission End Users, LDCs and Transmission-Connected Generators).

  Satisfaction with Outage Planning Procedures was 88% in 2024, which was better than the target of 85%.

Safety

- **Recordable Injury # of recordable injuries/illnesses per 200,000 hours worked**

  The number of recordable injuries/illnesses per 200,000 hours worked measures the work-related injuries or illnesses per 200,000 hours worked which result in: restricted work, lost time, loss of consciousness, medical attention beyond first aid, death, or any other significant work-related injury or illness diagnosed by a physician or other healthcare professional and are confirmed by a Hydro One Occupational Health Nurse. This measure only applies to employees of Hydro One and excludes contractors and the general public.

  The Recordable Injury rate was 0.5 in 2024, which was better than the target of 0.9.

System Reliability

- **T-SAIFI-S (Average Number of Sustained interruptions per Delivery Point)**

  Transmission System Average Interruption Frequency Index – Sustained is measured as the total number of unplanned sustained interruptions (1 minute or longer) that customers experienced per Delivery Point in a year. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

  The Transmission System Average Interruption Frequency Index – Sustained was 0.52 in 2024, which was better than the target of 0.55.

- **T-SAIFI-M (Average Number of Momentary interruptions per Delivery Point)**

  Transmission System Average Interruption Frequency Index – Momentary is measured as the total number of unplanned momentary interruptions (less than 1 minute) that customers experienced per Delivery Point in a year. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

  The Transmission System Average Interruption Frequency Index – Momentary was 0.44 in 2024, which was higher than the target of 0.42. This result is mainly due to an increase in inclement weather when compared to the previous 5-year average.

- **T-SAIDI (Average minutes of interruptions per Delivery Point)**

  Transmission System Average Interruption Duration Index is measured as the total number of minutes of unplanned interruptions that customers experienced per Delivery Point in a year. The measure is presented as interruption minutes per delivery point per year. Only sustained (1 minute and longer as per the Canadian Electricity Association (CEA) industry standard) interruptions contribute to this measure. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

The Transmission System Average Interruption Duration Index was 23.7 in 2024, which was better than the target of 31.9.

- **System Unavailability (%)**

  System Unavailability measures the unavailability of transmission lines and major transmission station equipment, due to direct automatic or forced manual outages caused by factors such as defective equipment, adverse weather, adverse environment, foreign interference and human element. While equipment unavailability doesn't necessarily lead to interruptions due to redundancy on Hydro One's transmission system, it is a leading indicator of future reliability erosion.

  Major station equipment includes Transmission lines, High voltage cables, Breakers, Transformers, Shunt capacitor banks, Shunt reactors, Series capacitor banks and Static VAR Compensators. This metric does not take into consideration the subordinate outages of healthy transmission equipment being removed out of service because of the outage of some other equipment.

  The System Unavailability was 0.50% in 2024, which was better than the target of 0.61%.

- **Unsupplied Energy (minutes)**

  Unsupplied Energy is the total energy not supplied to customers during the year, measured in system minutes, due to unplanned interruptions to all delivery points. This measure is normalized against the system peak to allow comparison with the performance of different sized utilities.

  The Unsupplied Energy was 8.2 minutes in 2024, which was better than the target of 8.8 minutes.

Asset and Project Management

- **Transmission System Plan Implementation Progress (%)**

  The Transmission System Plan Implementation Progress is measured as the total actual in-year sustainment, development, and operating expenditures for in-service additions over the total internal company scorecard budget expenditures for in-service additions, including any OEB carry-forward variance.

  In-service capital additions are tracked and reported in a manner consistent with the regulatory requirements of the transmission business and reported as a percentage value relative to the transmission plan.

  The Transmission System Plan Implementation Progress was 95% in 2024, which was lower than the target of 100%. The result is primarily due to timing shifts of major capital projects.

- **CapEx as % of Budget**

  Capex as a percentage of budget is measured as the total actual capital expenditures over the total amount budgeted (planned) capital expenditures in a year. This measure reflects the progress of Hydro One's capital expenditures towards the approved plan.

  The CapEx as a % of Budget was 114% in 2024, which was higher than the target of 100%. The result is primarily due to the accelerated timing of expenditures on major capital projects and third-party externally driven work.

- **Operations, Maintenance and Administration (OM&A) Program Accomplishment (composite index)**

  The Transmission OM&A Program Accomplishment (composite index) measure compares the weighted actual in-year accomplishment for significant Tx OM&A Programs against the weighted budget. There are eight programs monitored for this measure including: 1) Forestry Line Clearing; 2) Brush Control; 3) PCB Testing and Retro fill; and Station Preventive Maintenance programs which include 4) Power Equipment, 5) Ancillary Equipment, 6) Protection and Control, 7) Telecom and 8) Infrastructure.

  The Transmission OM&A Program Accomplishment composite index was 102% in 2024, which was better than the target of 100%.

- **Transmission Capital Accomplishment Index (TCAI) - (%)**

  The TCAI compares the weighted actual in-year accomplishment for significant transmission system renewal capital investments against the weighted budget. The investments covered by this metric represent the major assets associated with station centric and lines refurbishment projects being transformers, circuit breakers, protections and circuit kilometers of transmission line, as well as five programs including insulator replacement, wood pole replacement, shield wire replacement, tower foundations and steel structure coating.

  The Transmission Capital Accomplishment Index was 95% in 2024, which was lower than the target of 100%. This result is due to outage challenges impacting insulator replacement, as well as Circuit Breaker and Transmission Line Refurbishment project units due to timing shifts.

Cost Control

- **Total OM&A and Capital per Gross Fixed Asset Value (%)**

  The Total OM&A and Capital per Gross Fixed Asset Value is measured as the total capital and OM&A spend over the total gross book value of in-service assets. This measure demonstrates transmission cost effectiveness.

  The Total OM&A and Capital per Gross Fixed Asset Value was 8.49% in 2024, which was higher than the target of 8.0%. This result is due to the accelerated timing of capital expenditures and a lower gross fixed asset base due to timing shifts of major capital projects forecast to be completed in future years.

- **OM&A per Gross Fixed Asset Value (%)**

  OM&A per Gross Fixed Asset Value is measured as the total OM&A over the gross book value of fixed assets. The measure demonstrates transmission cost effectiveness.

  The OM&A per Gross Fixed Asset Value was 2.0% in 2024, which was higher than the target of 1.8%. This result is due to higher OM&A and a lower gross fixed asset base, due to timing shifts of major capital projects which are forecast to be completed in future years.

- **Line Clearing Cost per Kilometer ($/km)**

  The Line Clearing Cost per Kilometer is measured as the total line clearing costs over the total number of kilometers of transmission line. This measure shows the cost associated with line clearing activities completed in the year, per kilometer of line.

  The Line Clearing Cost per Kilometer was $2,426 in 2024, which was better than the target of $2,854.

- **Brush Control Cost per Hectare ($/Ha)**

  The Brush Control Cost per Hectare is measured as the total cost of brush control completed in the year, per hectare of brush.

  The Brush Control Cost per Hectare was $2,402 in 2024, which was higher than the target of $1,669. This result is due to the elimination of herbicide use in some areas, and increased costs related to helicopter requirements in remote areas.

Customer Impact Assessment on Renewable Generation

- **% On-time completion of Customer Impact Assessments on Renewable Generation**

  For Transmission-connected generators, Hydro One is obligated under the Transmission System Code to complete a customer impact assessment (CIA) for renewables within 150 days. The % of on-time completion of renewables CIAs is measured as the total number of renewables CIAs completed within the required timeline over the total number of renewables CIAs completed in the year.

  No Customer Impact Assessments on Renewable Generation were reported in 2024.

Regional Infrastructure Planning & Long-Term Energy Plan (LTEP) Right-Sizing

- **Regional Infrastructure Planning progress - Deliverables met (%)**

  Regional Infrastructure Planning Progress – Deliverables met measures progress in meeting the deliverables of the regional infrastructure planning process, including meeting the Transmission System Code (“TSC”) prescribed timelines and delivering the required products. The number of deliverables will vary in a given year. Deliverables include plans, reports and Local Distribution Companies (LDC) status update letters. Deliverables met is measured as the number of correct deliverables that meet the TSC prescribed timelines over the total number of deliverables.

The Regional Infrastructure Planning Progress – Deliverables Met was 100% in 2024, which met the target of 100%.

- **End-of-Life Right-Sizing Assessment Expectation**

  This qualitative measure gauges Hydro One’s performance in meeting the expectation that no more than two (2) assessment opportunities for right-sizing the replacement of end-of-life equipment to facilitate future growth are missed during the year, for all regions assessed in the year as part of the Regional Planning Process. The number of regions assessed may vary in each year. Measure Calculation: N/A as this is a qualitative measure – either Met or Not Met

  The End-of-Life Right Sizing Assessment Expectation was met in 2024.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  Liquidity: Current Ratio measures the ratio of current assets to current liabilities. Current assets are defined as cash or other assets to be converted to cash within the year. Current liabilities are defined as short-term debts or financial obligations that will become due within the year.

  The Liquidity: Current Ratio was 0.21 in 2024.

- **Leverage: Total Debt to Equity Ratio**

  The Total Debt to Equity Ratio is measured as the total short-term and long-term debt over the total equity. This measure reflects Hydro One’s financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors, while remaining within the OEB-mandated 60% to 40% debt-to-equity structure (a ratio of 1.5).

The Leverage: Total Debt to Equity Ratio was 1.65 in 2024.

- **Profitability: Regulatory Return on Equity**

  Achieved Regulatory Return on Equity (ROE) measures the OEB-approved ROE that is embedded in the transmitter's base rates. ROE is the rate of return that the utility is allowed to earn through its transmission rates, as approved by the OEB.

  The Profitability: Regulated Return on Equity was 10.96% in 2024.

Note to Readers of Fiscal 2024 Scorecard MD&A

The information provided by Transmission Business on their future performance (or what can be construed as forward-looking information) may be subject to several risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance.

Words such as “expect,” “anticipate,” “intend,” “attempt,” “may,” “plan,” “will”, “can”, “believe,” “seek,” “estimate,” and variations of such words and similar expressions are intended to identify such forward-looking statements and information. Such statements include, but are not limited to, references to service quality metrics, including their purposes and frequency of measurement; the development of the transmission system and the progress of the implementation of the transmission system plan; the timing for System Access and System Renewal projects and other system renewal projects; performance measurements regarding end-of-life right-sizing equipment assessment opportunities; financial measurements and their implications; and targets. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Some of the factors that could cause such differences include the scope, duration, and impacts of infectious diseases, including the COVID-19 pandemic and related developments including government and the company’s response and mitigation measures, legislative or regulatory developments, government policy and program developments, an unexpected increase in call centre volumes, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management’s best judgment on the reporting date of the performance scorecard and could be markedly different in the future. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

Hydro One Networks Electricity Transmitter Scorecard

Year End Results

Performance Outcomes	Performance Categories	Measures		2019	2020	2021	2022	2023	Actual 2024	JRAP Target 2024
	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs (%)		10.9%	11.4%	8.3%	9.3%	10.9%	13.6%	10.8%
	Customer Satisfaction	Overall Customer Satisfaction (%)		87%	83%	92%	88%	88%	85%	88%
		Satisfaction with Outage Planning Procedures (%)		84%	71%	82%	78%	72%	88%	85%
	Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)		0.8	0.9	0.7	0.6	0.6	0.6	0.9
	System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)		0.59	0.50	0.49	0.64	0.54	0.52	0.55
		T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)		0.43	0.40	0.42	0.43	0.46	0.44	0.42
		T-SAIDI (Ave. minutes of interruptions per Deliver Point)		38.9	61.3	21.0	61.0	25.9	23.7	31.9
		System Unavailability (%)		0.89%	0.83%	0.67%	0.76%	0.52%	0.50%	0.61%
		Unsupplied energy (minutes)		13.3	8.0	7.1	13.3	6.4	8.2	8.8
	Asset & Project Management	Transmission System Plan Implementation Progress (%)		101%	101%	99%	101%	97%	95%	100%
		CapEx as % of Budget (%)		99%	104%	112%	114%	97%	114%	100%
		OM&A Program Accomplishment (composite index)		88	93	105	96	109	102	100
		Transmission Capital Accomplishment Index (TCAI) - (%)			101%	99%	80%	91%	95%	100%
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)		7.4%	7.9%	8.3%	7.6%	7.8%	8.5%	8.0%
		OM&A per Gross Fixed Asset Value (%)		1.9%	2.1%	2.0%	2.2%	2.2%	2.0%	1.8%
		Line Clearing Cost per kilometer ($/km)		$ 3,817	$ 3,368	$ 2,211	$ 2,140	$ 2,210	$ 2,426	$ 2,854
		Brush Control Cost per Hectare ($/Ha)		$ 1,924	$ 1,538	$ 1,807	$ 2,003	$ 1,916	$ 2,402	$ 1,669
	Connection of Renewable Generation	% on-time completion of renewables customer impact assessments (CIAs)		100%	100%	100%	100%	No CIAs in 2023	100%	100%
	Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing	Regional Infrastructure Planning progress - Deliverables met (%)		100%	100%	95%	100%	100%	100%	100%
		End-of-Life Right-Sizing Assessment Expectation		Met	Met	Met	Met	Met	Met	Met
	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.20	0.28	0.27	0.23	0.21	0.21	N/A
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.52	1.50	1.40	1.37	1.48	1.65	N/A
		Profitability: Regulatory Return on Equity	Deemed	N/A	8.52%	8.52%	8.52%	9.36%	9.36%	N/A
			Approved	9.53%	9.29%	9.30%	9.92%	10.80%	10.96%	N/A

Section 2.1

2024 Transmission Capital Performance Report

TRANSMISSION CAPITAL PERFORMANCE REPORT – 2024

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Performance Report provides an overview of Hydro One Networks Inc.'s (Hydro One) performance in 2024 in relation to the overall transmission capital envelope for the year and reviews the performance of individual projects and programs. It addresses both capital expenditures and in-service additions (ISA) delivered by Hydro One.

1.2 APPROVED CAPITAL INVESTMENT

In Hydro One's application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached a settlement with all parties (the Settlement Proposal) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, the OEB approved Hydro One's 2023 to 2027 capital expenditures and ISA.[1]

In December 2022, Hydro One revised the capital expenditure and ISA forecast on a multi-year envelope and OEB-category basis to implement the OEB-approved Settlement Proposal (the "Forecast"). This was the first time Hydro One allocated the impact of the Settlement Proposal at the project and program level. The Forecast is the basis for the Program and Project level variances described in this Capital Performance Report.

2.0 PERFORMANCE AT THE OVERALL ENVELOPE AND OEB CATEGORY

Table 1 below presents a breakdown of the actual 2024 transmission capital expenditures and ISA by OEB investment category and compares them against OEB-approved values. The primary focus of this report is on the Transmission System Access, System Renewal, and System Service categories. The Transmission General Plant category is discussed in the General Plant Capital Performance Report.

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 and p.257-258.

Table 1 - 2024 Transmission Capital Expenditures and ISA[2]

OEB Category	Capital Expenditures – 2024			In-Service Additions – 2024		
	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)
System Access	$74.6	$108.9	$34.3	$51.4	$47.9	-$3.5
System Renewal	$1,150.6	$1,182.2	$31.6	$1,105.6	$932.2	-$173.4
System Service	$107.0	$152.4	$45.4	$21.7	$93.8	$72.1
General Plant	$121.4	$126.7	$5.3	$149.6	$115.1	-$34.5
Productivity[4]	-$64.2			-$64.2		
Total	**$1,389.4**	**$1,570.3**	**$180.9**	**$1,264.2**	**$1,189.0**	**-$75.2**

In 2024, Hydro One's transmission capital expenditures for 2024 were 13% above the OEB-approved amount and ISAs were 6% below the OEB-approved amount. Transmission capital expenditures were higher largely due to increased spending in the System Service and System Access categories. Increased spending in System Service was primarily driven by mandatory transmission work required by governmental authorities (Externally Driven Work). The decrease in transmission ISAs was due to lower System Renewal additions. Furthermore, expenditure variances at the OEB-category level were impacted by inflationary pressures including rising costs of goods, services, and labour. Hydro One has responded to these circumstances by reprioritizing and re-pacing its capital portfolio where it was possible to do so. The OEB categories and associated variance explanations are summarized below.

System Access: System Access capital expenditures were $34.3M above the OEB-approved amount. This variance was primarily driven by Centennial TS: Project Connect PowerCo (T-SA-New) which is mandatory for the connection of a customer facility, and by the Wallaceburg Transformer Station Conversion from 115 kV to 230 kV (T-SA-New). System Access ISAs were $3.5M below the OEB-approved amount. This variance was primarily driven by a customer delay to select a route for the Commerce TS New 230 kV Customer Connection project (T-SA-01).

---

[2] Does not include Hydro One affiliates or future Affiliate Transmission Lines Projects (ATP).
[3] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 (Table 22 and 23)
[4] Productivity is reflected in Actual expenditures.

System Renewal: System Renewal capital expenditures were $31.6M above the OEB-approved amount. This variance was primarily driven by Bruce A 500kV - Replace ABCB & Yard Reconfiguration (T-SR-02) which was accelerated at the request of Bruce Power. System Renewal ISAs were $173.4M below the OEB-approved amount. This variance is primarily driven by Bruce A 500kV - Replace ABCB & Yard Reconfiguration (T-SR-02) where the timing of a partial ISA shifted through discussions with Bruce Power, the E1C Transmission Line Refurbishment project (T-SR-13) which was deferred due to outage constraints with the radial line requiring the project plan to be modified, and Lauzon T6, T5 & Component Replacement (T-SR-03) where the timing of a partial ISA shifted to 2025.

System Service: System Service expenditures were $45.4M above the OEB-approved amount. This variance was primarily driven by the addition of the Waasigan Transmission Line Project - Station Work (T-SS-Other-New) and by the Barrie Area Transmission Upgrade (T-SS-Other) due to customer-initiated delays and the completion of trailing work. System Service ISAs were $72.1M above the OEB-approved amount. This variance is primarily driven by Chatham SS x Lakeshore TS: Stations Work (T-SS-07) which was completed a year ahead of schedule, Sudbury Area Reinforcement - X25S Unbundling (T-SS-Other) due to a timing shift during project development, and Richview x Trafalgar 230kV Conductor Upgrade (T-SS-04) due to earlier partial in-servicing of the project.

3.0 PERFORMANCE AT THE PROJECT AND PROGRAM LEVEL

Hydro One takes an integrated approach to transmission portfolio management and manages to the overall capital envelope. The approach recognizes that changes at both the project and program levels will occur. Individual variances, be it an annual or project total level are to be expected given the magnitude and complexity of the work being performed. Each project involves a unique combination of elements related to the scope of work included and site conditions, and is undertaken pursuant to a defined project delivery process with a range of expected outcomes as defined by the Association for the Advancement of Cost Engineering (AACE) class of estimate.[5] Projects are typically released for execution and funded based on a Class 3 estimate. As projects are executed, they are managed to allow Hydro One to be responsive to execution challenges and

---

[5] AACE estimate classification is discussed in EB-2021-0110, TSP Section 2.10.

update project scope, where required, while continuing to deliver the projects according to Hydro One's project delivery process.

At Hydro One, projects are governed with a focus on adherence to the total project budget. In year amounts are managed on a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in this report in reference to project total variances and overall project schedule variances. Programs are different in that the budget is set annually and are managed and governed against these budgets. As such, program performance is discussed in the context of adherence to annual budgets.

3.1 OVERVIEW

The projects and programs discussed in this report represent 96% of the 2024 actual ISA that is shown in Table 1 (for the System Access, System Renewal and System Service categories) and as such provide a very strong indication of the overall portfolio performance.

Hydro One's performance in relation to material[6] projects with AACE Class 3 estimates at the time the Settlement Proposal was implemented (see Section 1.2), are presented in Figure 1 below.[7] The blue vertical lines in the cost variance chart are placed at -20% and +30% which is the range of expected outcomes that most commonly aligns with an AACE Class 3 estimate, and representative of the typical project definition work completed at the time of business case approval at Hydro One. The figure shows a relatively tight dispersion of cost performance with the majority of projects (69% = 27 of 39) having project variances below the AACE upper range, which is a reasonable result given the significant cost pressures experienced in recent years. The overall variance for the 39 projects is +10% which is well within the AACE Class 3 estimate range. Hydro One utilizes its Capital Project Delivery model to manage and remain effective in executing projects within the range anticipated when the project budgets were established. This is particularly true for

[6]Greater than or equal to $3M, and with actual or planned ISA in 2024
[7] This provides a more consistent evaluation of AACE Class 3-based project estimates against the AACE Class 3 estimate accuracy range.

larger projects (>$30M) that are subject to increased rigour and scrutiny as part of the project delivery process.

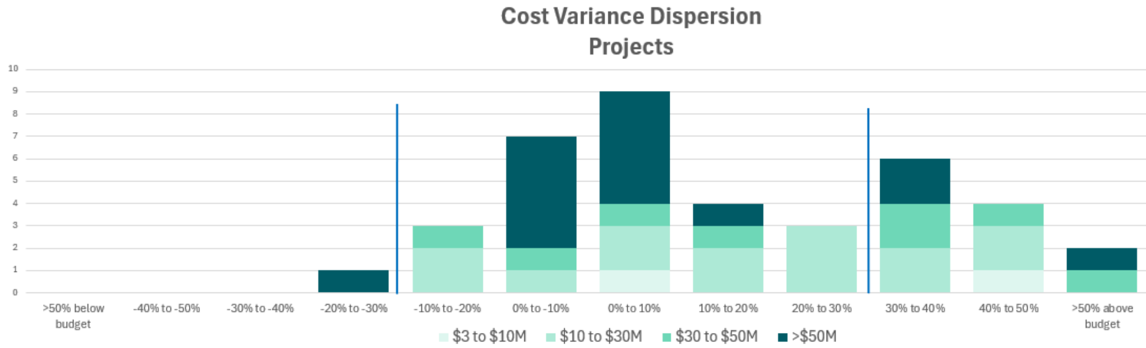

Figure 1: Material Projects' Cost Variance Dispersion[8]

Similarly, Figure 2 below shows that the majority of projects (79% = 31 of 39) were completed / forecast to complete on plan, within 12 months of baseline.

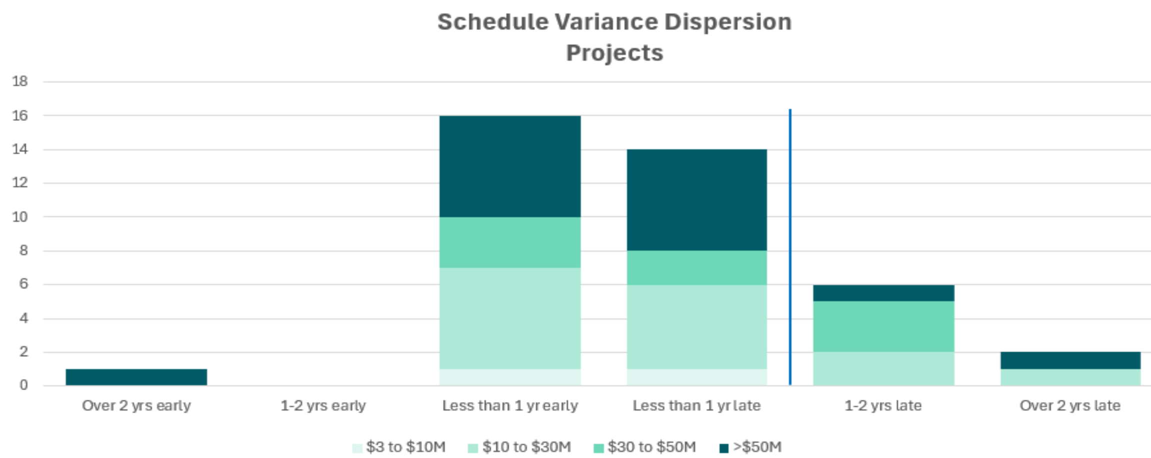

Figure 2: Material Projects' Schedule Variance Dispersion[9]

3.2 PERFORMANCE DEFINITIONS

Projects and programs with planned or actual ISA in 2024 greater than or equal to $3M have been summarized in the tables below along with variance explanations. The

[8] Based on actual cost for completed projects and forecast cost at completion for projects still in progress.

[9] Based on actual in-service date for completed projects and forecast in-service date for projects still in progress.

thresholds used by Hydro One to identify “material variances” were determined using the following criteria[10]:

- **Cost Variances** – Material cost variances were identified where the in-year variance in cost for programs, or the total project end cost variance is greater than or equal to $1M and greater than or equal to 10% of planned values.
- **Scope Variances** – Material scope variances arise if the functional scope changes by +/-20% or more.
- **Date Variances** – Material date variances were identified for projects where the actual or projected in-service year shifted from 2024 or earlier, to a later year.

The reasons for variances in individual projects and programs fall into four categories: 1) Emergent Needs, 2) Execution Factors, 3) Work Definition, and 4) Reprioritization. These categories are used to identify the reasons for variances at the project and program level and are defined below.

Emergent Needs

Emergent needs are investments that Hydro One made in response to a change of priority due to equipment condition or failure, as well as customer needs.

Execution Factors

Execution factors represent advances or delays encountered during the execution phase of work which can include timing changes that arise as a result of changing conditions, risks or priorities that need to be addressed during execution. As risks materialize, plans are adjusted to accommodate the change and mitigate the overall impact to cost, schedule and resources. This can change the year in which the project goes in-service without materially changing the in-service amount or affecting the overall scope of work completed. Some of the main causes of delays are outage deferrals or cancellations, material delivery and logistics factors as well as customer needs.

Work Definition

[10] This report’s variance criteria conform with Hydro One’s internal variance reporting criteria which focuses on projects and programs with positive variances greater than the thresholds described below.

Work definition variances arise from the process of refining a project's scope, the estimated budget and schedule as the project moves from the high-level planning phase to design and estimate, and execution phases. As the project is refined, there may be increases or decreases to the project cost as a result of new or changing information that becomes known during the design and estimation phase or in the execution stage of work.

Reprioritization

Reprioritization includes investments that are accelerated or deferred. Hydro One adjusts its capital investments through annual planning and in-year redirection processes.

4.0 PROJECT PERFORMANCE

As summarized in Table 3 below, transmission projects are well managed with a focus on adherence to the overall project total budget and project schedule.

1 **Table 3 - Transmission Project Summary**

Project Characteristics			2024 Tx Capital Expenditures ($M)		2024 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
System Access													
Oneida Battery Park	Complete	T-SA-Other	0.0	4.7	0.0	8.2	0.0	8.4	8.4	-	2024	n/a	Emergent Needs
Windsor NextStar TS: 230 kV/27.6 kV DESN	Complete	T-SA-Other	12.9	10.9	47.9	34.0	48.2	34.1	-14.1	2024	2024	0	Not Applicable
System Renewal													
Integrated Station Investment													
Beck 1 SS: ABCB Replacement	Execution	T-SR-02	8.5	4.4	3.4	4.3	54.2	40.8	-13.4	2026	2025	-1	Not Applicable
Beck 2 TS: ABCB Replacement	Complete	T-SR-02	0.0	8.1	0.0	29.4	122.2	127.1	4.9	2023	2024	1	Execution Factors
Bridgman TS Load Station Transformer Replacement	Execution	T-SR-03	9.0	16.7	21.9	30.2	69.3	95.4	26.1	2024	2026	2	Execution Factors
Bruce B SS: ABCB Replacement	Complete	T-SR-02	4.6	3.1	7.3	2.6	182.3	175.7	-6.6	2024	2022	-2	Not Applicable
Cecil TS: T1 & Component Replacement	Complete	T-SR-03	0.0	2.2	0.0	7.5	18.5	18.8	0.3	2023	2023	0	Not Applicable
Cherrywood TS: 500kV ABCB Replacement (Phase 3-1)	Execution	T-SR-02	11.0	14.1	19.5	18.8	74.8	72.5	-2.3	2025	2025	0	Not Applicable
Claireville TS: Component Replacement	Execution	T-SR-01	3.5	4.7	13.0	5.6	27.9	34.9	6.9	2025	2025	0	Execution Factors
Edgeware TS: PCT & Component Replacement	Complete	T-SR-03	0.8	1.8	13.2	14.2	13.2	14.2	1.0	2024	2024	0	Not Applicable
Fairbank TS: T1, T2, T3, T4, PCT & LV Yard Replacement	Complete	T-SR-03	6.0	10.2	31.2	16.1	70.6	79.7	9.2	2024	2024	0	Execution Factors
Gage TS: T3, T4, T5, T6, PCT & Switchyard Reconfiguration	Complete	T-SR-03	2.4	8.3	2.4	10.9	84.2	83.1	-1.1	2023	2024	1	Execution Factors
Glendale TS: Station Refurbishment and Reconfiguration	Planning	T-SR-03	8.5	1.2	11.5	0.0	52.9	19.1	-33.8	2027	2026	-1	Not Applicable
John TS: T5 and T6 Transformer Replacement	Execution	T-SR-03	10.6	13.2	10.1	0.0	25.9	29.1	3.2	2025	2025	0	Work Definition

[11] Phases: Planning, Execution, or Complete.

Project Characteristics			2024 Tx Capital Expenditures ($M)		2024 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Keith TS: T11, T12 & Component Replacement	Complete	T-SR-01	0.0	5.7	0.0	7.7	42.0	49.3	7.3	2023	2023	0	Emergent Needs
Kirkland Lake TS: Component Replacement	Execution	T-SR-03	4.5	11.4	19.9	26.7	27.9	38.1	10.1	2025	2027	2	Execution Factors
Lake TS: T2 & Component Replacement	Complete	T-SR-03	8.6	8.1	9.0	11.0	39.9	11.1	-28.8	2026	2024	-2	Not Applicable
Lambton TS: T7/T8, T5/T6, DESN Replacement	Complete	T-SR-03	1.4	6.9	1.4	17.3	69.9	71.4	1.5	2023	2024	1	Work Definition
Lennox TS: ABCB Component Replacement	Execution	T-SR-02	8.1	11.1	16.5	23.0	143.2	153.9	10.7	2026	2026	0	Not Applicable
Lincoln Heights TS: T1/T2 & Component Replacement	Complete	T-SR-03	5.0	7.6	7.8	11.3	20.2	24.3	4.1	2024	2024	0	Execution Factors
Longwood TS: Component Replacement	Execution	T-SR-03	4.3	3.8	0.0	14.1	14.7	20.0	5.4	2025	2026	1	Work Definition
Mackenzie TS: Component Replacement – Phase 1	Execution	T-SR-01	21.5	30.0	18.9	0.0	47.3	61.8	14.5	2025	2025	0	Work Definition
Main TS: T3, T4 & Component Replacement	Execution	T-SR-03	9.6	9.5	45.5	0.0	48.0	70.4	22.4	2024	2025	1	Execution Factors
Marathon TS: Component Replacement	Planning	T-SR-01	10.5	0.7	11.7	0.0	30.7	35.0	4.4	2026	2027	1	Work Definition
Middleport TS: ABCB Replacement	Execution	T-SR-02	23.5	21.7	34.7	36.8	178.1	168.3	-9.8	2025	2025	0	Not Applicable
Middleport TS: T6 Replacement	Execution	T-SR-01	10.9	7.7	10.6	9.2	24.9	25.0	0.1	2025	2025	0	Not Applicable
Milton SS: Component Replacement	Execution	T-SR-01	3.2	6.1	6.2	6.7	20.0	28.4	8.4	2024	2025	1	Execution Factors:
Nanticoke TS: ABCB Replacement	Execution	T-SR-02	6.0	13.0	0.0	10.8	79.0	82.6	3.6	2026	2027	1	Not Applicable
Orangeville TS: Load Station Transformer Replacement	Complete	T-SR-03	2.2	6.7	11.1	21.6	35.6	47.3	11.7	2023	2024	1	Execution Factors
Otto Holden TS: T3/T4 & Component Replacement	Execution	T-SR-01	11.0	25.4	10.1	0.0	68.7	107.5	38.8	2027	2028	1	Work Definition
Pine Portage SS: Component Replacement	Complete	T-SR-01	3.6	2.7	23.9	4.0	38.4	34.3	-4.1	2024	2024	0	Not Applicable
Porcupine TS: Component Replacement	Execution	T-SR-01	17.1	23.0	34.0	33.5	88.8	91.3	2.5	2026	2026	0	Not Applicable
Rabbit Lake SS: Component Replacement	Execution	T-SR-01	3.6	5.0	8.3	9.2	29.3	36.7	7.5	2024	2025	1	Work Definition

Project Characteristics			2024 Tx Capital Expenditures ($M)		2024 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Rexdale TS: M/C Switchgear & Component Replacement	Execution	T-SR-03	7.5	13.9	16.8	26.0	33.6	64.5	30.9	2026	2027	1	Execution Factors
Sarnia Scott TS: T5 & Component Replacement	Complete	T-SR-01	5.5	5.9	22.2	25.1	26.2	29.1	2.9	2024	2024	0	Execution Factors
Scarboro TS: T23 & Component Replacement	Execution	T-SR-03	4.7	4.5	0.0	3.3	23.3	27.0	3.7	2027	2026	-1	Execution Factors
Seaforth TS: T1, T2, T5, T6, PCT & Component Replacement	Execution	T-SR-01	17.1	19.6	53.6	0.0	53.6	76.2	22.6	2024	2027	3	Work Definition
Slater TS: T2/T3 & Component Replacement	Complete	T-SR-03	3.2	9.1	5.3	11.7	28.3	24.8	-3.5	2024	2024	0	Not Applicable
Thorold TS: T1, MV Switchyard & Component Replacement	Complete	T-SR-03	1.3	6.7	3.1	9.6	31.8	43.8	12.1	2024	2024	0	Work Definition
Wawa TS: Component Replacement	Execution	T-SR-01	12.8	16.0	12.0	25.0	60.1	95.5	35.4	2026	2028	2	Execution Factors
Whitedog Falls SS: Component Replacement	Execution	T-SR-01	2.5	1.3	6.3	1.6	8.8	12.5	3.7	2025	2025	0	Work Definition
Wilson TS: T1 & Component Replacement	Complete	T-SR-03	5.3	7.3	46.0	49.0	46.0	49.3	3.3	2024	2024	0	Not Applicable
Wingham TS: T1, T2, PCT & Component Replacement	Complete	T-SR-03	5.3	6.7	13.0	17.2	23.0	34.1	11.1	2024	2024	0	Execution Factors
Overhead Lines Refurbishment Projects, Component Replacement Programs													
B7/B8 Transmission Line Refurbishment	Execution	T-SR-Other	2.5	0.7	3.2	0.0	3.2	8.8	5.6	2024	2025	1	Work Definition
A4L Transmission Line Refurbishment	Planning	T-SR-13	24.4	0.0	12.6	0.0	49.1	36.4	-12.7	2025	2033	8	Not Applicable
B5/6C Transmission Line Refurbishment	Execution	T-SR-13	3.9	4.2	0.0	13.4	24.0	22.6	-1.4	2025	2026	1	Not Applicable
D2/3H Transmission Line Refurbishment	Planning	T-SR-13	16.7	0.1	10.6	0.0	96.3	188.7	92.4	2026	2031	5	Work Definition
E1C Transmission Line Refurbishment	Planning	T-SR-13	14.0	0.1	8.3	0.0	55.2	68.0	12.8	2026	2031	5	Reprioritization
K1/K2 Transmission Line Refurbishment	Planning	T-SR-13	3.0	0.0	3.9	0.0	3.9	20.9	17.1	2024	2029	5	Reprioritization
K4 Transmission Line Refurbishment	Complete	T-SR-13	1.5	10.1	6.6	12.2	6.6	12.5	5.9	2024	2024	0	Work Definition
Q3M6 Transmission Line Refurbishment	Complete	T-SR-13	0.6	2.4	0.0	3.8	3.6	3.9	0.3	2024	2024	0	Not Applicable

Project Characteristics			2024 Tx Capital Expenditures ($M)		2024 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[11]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance (Years)**	**Variance Category**
L22H Transmission Line Refurbishment	Planning	T-SR-13	10.6	0.0	6.2	0.0	61.3	64.2	2.9	2026	2035	9	Not Applicable
Protection and Automation													
Cooksville Microwave Replacement	Complete	T-SR-Other	0.9	7.3	6.0	9.1	6.3	9.1	2.8	2024	2024	0	Execution Factors
Ottawa Ring 9 Fibre Infrastructure Development	Execution	T-SR-17	6.7	14.8	0.0	9.1	22.0	27.9	5.9	2026	2025	-1	Execution Factors
<u>System Service</u>													
Enabling Facilities - Government Project													
Keith TS: Replace 6-115 kV Breakers	Execution	T-SS-New	0.0	6.6	0.0	6.0	0.0	9.3	9.3	-	2025	n/a	Emergent Needs
Inter Area Network Capability													
Chatham SS x Lakeshore TS: Stations Work	Complete	T-SS-07	9.1	9.7	0.0	27.2	32.4	29.5	-2.8	2025	2024	-1	Not Applicable
Sudbury Area Reinforcement - X25S Unbundling	Complete	T-SS-Other	11.7	7.8	24.3	19.7	24.4	20.4	-4.0	2024	2024	0	Not Applicable
Local Area Supply Adequacy													
Barrie Area Transmission Upgrade	Complete	T-SS-Other	2.5	12.7	2.5	14.3	105.1	100.1	-4.9	2023	2023	0	Not Applicable
Richview x Trafalgar 230kV Conductor Upgrade	Execution	T-SS-04	11.7	21.1	20.0	19.1	59.3	82.6	23.3	2026	2026	0	Execution Factors

1

The following is an overview of the larger cost and schedule variances for projects with AACE Class 3 estimates at the time the Settlement Proposal was implemented (see Section 1.2).

The **Wawa TS: Component Replacement (T-SR-01)** project is forecasted to exceed its budget by $35.4M predominantly due to cost pressures outlined in Section 2.0, as well as design and staging plan maturity. Increased project complexity and requirements for several temporary line bypasses to accommodate a power-outage staging plan in the region also contributed to the variance. **Rexdale TS: M/C Switchgear & Component Replacement (T-SR-03)** is forecasted to exceed its budget by $30.9M primarily due execution factors including a more complex staging plan to align with Toronto Hydro's requirements, outage challenges, and unforeseen construction complexities related to in-situ equipment replacement. **Bridgman TS Load Station Transformer Replacement (T-SR-03)** is forecasted to exceed its budget by $26.1M due to changes in the contingency tie cable design to meet Toronto Hydro's requirements, constructability challenges, and Toronto Hydro's cost escalations for cable relocation work. These factors, along with material delivery delays and outage coordination requirements also led to schedule delays. **Richview x Trafalgar 230kV Conductor Upgrade (T-SS-04)** is forecasted to exceed its budget by $23.3M primarily due to changes in project definition assumptions including permit-related requirements, construction complexity crossing multiple highways and procurement escalations. Lastly, **Main TS: T3, T4 & Component Replacement (T-SR-03)** is forecasted to exceed its budget by $22.4M. The increase in cost is attributed to execution related challenges and equipment cost increases. The project is being undertaken in a congested urban setting resulting in unanticipated design and construction challenges, including major design changes, restricted resource movement and material flow, unanticipated underground obstructions, complex excavation shoring, and complex commissioning requirements. These factors, combined with permit delays, also led to a schedule delay from 2024 to 2025.

The following is an overview of the larger cost and schedule variances for projects that did not have an AACE Class 3 estimates at the time the Settlement Proposal was implemented (see Section 1.2). The **D2/3H Transmission Line Refurbishment (T-SR-13)** project is forecasted to exceed its budget by $92.4M. This project is in an early planning phase and is on hold as the project is assessed. **Otto Holden TS: T3/T4 &**

Component Replacement (T-SR-01) project is forecasted to exceed its budget by $38.8M mainly due to additional infrastructure needs. Two new autotransformers and a 115 kV yard must be installed in the new Antoine TS and connected to the existing Otto Holden TS through a short 230 kV transmission line. In addition, as the project has matured, scope changes were required to account for complex and high-risk outage requirements, OPG's safe site access requirements and impacts to the interconnection with Quebec, safety concerns with the condition of the existing property, and the unavailability of space for expansion. **Seaforth TS: T1, T2, T5, T6, PCT & Component Replacement (T-SR-01)** is forecasted to exceed its budget by $22.6M due to a combination of project maturity and cost escalation factors related to scope changes which included location changes for all four transformers, and project adjustments to maintain the current medium-voltage switchyard, which also contributed to the schedule delay from 2024 to 2027. **Mackenzie TS: Component Replacement - Phase 1 (T-SR-01)** is forecasted to exceed its budget by $14.5M. This increase is primarily attributable to a combination of project maturity and execution related factors. Lastly, a subset of **Transmission Line Refurbishment (T-SR-13)** projects have been impacted by maturity and cost escalation factors and have subsequently been deferred to manage expenditures within the overall capital envelope.

5.0 PROGRAM PERFORMANCE

Overall, the aggregate capital expenditure and ISA amounts for System Renewal programs in Table 4 below were above the overall Forecast amounts (+$49M and +$36M respectively).

Table 4 - Transmission Program Summary

Program Characteristics		2024 Tx Capital Expenditures ($M)			2024 Tx In-Service Additions ($M)			2024 Tx Units				Performance
Program Description	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Unit Description**	**Forecast**	**Actual**	**Variance**	**Variance Category**
System Renewal												
Wood Pole Structure Replacement	T-SR-04	56.5	88.7	32.2	56.2	86.1	29.9	# of Structures	943	952	9	Execution Factors
Steel Structure Coating Program	T-SR-05	19.7	27.7	8.1	19.7	27.9	8.2	# of Structures	470	504	34	Execution Factors
Tx Lines Foundation Assess/Clean/Coat, Life Extension & Tower Member Refurbishment Program	T-SR-06	14.2	17.8	3.7	14.1	18.1	3.9	# of Structures	1329	1459	130	Reprioritization
Transmission Line Shieldwire Replacement	T-SR-07	13.0	19.9	7.0	12.9	20.9	8.0	# of km	297	190	-107	Work Definition
Transmission Line Insulator Replacement	T-SR-08	77.5	64.3	-13.2	81.3	66.4	-14.9	# of Circuit Structures	3694	3084	-610	Not Applicable
Transmission Station Demand, Spares and Targeted Assets	T-SR-09	65.7	71.3	5.6	49.8	57.5	7.7	n/a	n/a	n/a	n/a	Reprioritization
Protection Relay Replacement Program	T-SR-10	10.4	11.4	1.0	9.8	1.4	-8.4	# of Upgrades	45	8	-37	Execution Factors
Tx Lines Emergency Replacements	T-SR-15	11.0	8.0	-2.9	10.7	7.8	-2.9	# of work orders	115	87	-28	Execution Factors
Tx Lines Virtual Asset Inspection	T-SR-Other	3.0	9.3	6.3	3.0	5.4	2.4	CCT-Km inspected	2210	15770	13560	Reprioritization
Tx Lines - TC112 ROW projects	T-SR-Other	2.5	4.1	1.5	2.5	4.5	2.0	# of Asset Structures	10	9	-1	Work Definition
Tx RTU Replacement Program	T-SR-Other	6.7	6.2	-0.5	4.2	2.9	-1.3	# of RTUs	8	6	-2	Execution Factors
Online DGA Monitor Program	T-SR-Other	3.1	3.4	0.4	3.1	4.5	1.4	# of Installations	14	18	4	Execution Factors

The **Wood Pole Structure Replacement (T-SR-04)** program had higher expenditures due to difficult terrain and access, and higher contract costs associated with accessing and setting up remote work headquarters (e.g. ice roads, bypasses, helicopter deliveries). These higher expenditures were partially funded through redirection from the **Transmission Lines Insulator Replacement (T-SR-08)** program, as outage constraints and cancellations deferred planned work.

Other programs that experienced material variances were:

- The **Steel Structure Coating (T-SR-05)** program had higher expenditures due to the work complexity and higher than forecasted costs for live-line work.
- The **Tx Lines Foundation Assess/Clean/Coat, Life Extension & Tower Member Refurbishment (T-SR-06)** program had higher expenditures mainly due to additional units that were completed.
- The **Transmission Shieldwire Replacement (T-SR-07)** program had higher expenditures and reduced accomplishment due to more complex work including OPGW replacement rather than shieldwire, which is more costly due to tower peak modifications and required fibre optic cable work.
- The **Transmission Station Demand, Spares and Targeted Assets (T-SR-09)** program had increased expenditures to purchase a spare transformer unit that was originally planned for 2025.
- The **Protection Relay Replacement (T-SR-10)** program had higher expenditures due to the advancement of construction work; outage availability limited work completion (unit accomplishments and ISA), which are now expected to be completed in future years.
- **Tx Lines Emergency Replacements (T-SR-15)** had lower expenditures and accomplishments due to fewer emergency failures.
- The **Transmission Lines Virtual Asset Inspection (T-SR-Other)** program had higher expenditures and accomplishment due to additional inspections.
- **Tx Lines - TC112 ROW Projects (T-SR-Other)** had higher expenditures as most of the work was bridge related which is more expensive and takes longer to complete.
- The **RTU Replacement Program (T-SR-Other)** had lower accomplishments due to work deferral to 2025 as a result of complex outage requirements and resourcing.

- The **Online DGA Monitor (T-SR-Other)** program had trailing ISA and accomplishments from 2023. Capital expenditures were undertaken in 2023 but could not be in-serviced due to outage and construction constraints. This resulted in higher ISA and accomplishments in 2024 despite capital expenditures being close to plan.

Section 2.2

2024 Distribution Capital Performance Report

DISTRIBUTION CAPITAL PERFORMANCE REPORT – 2024

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Performance Report provides an overview of Hydro One Networks Inc.'s (Hydro One) performance in 2024 in relation to the overall Distribution capital envelope for the year and reviews the performance of individual projects and programs. It addresses both capital expenditures and in-service additions (ISA) delivered by Hydro One.

1.2 APPROVED CAPITAL INVESTMENT

In Hydro One's application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached a settlement with all parties (the Settlement Proposal) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, the OEB approved Hydro One's 2023 to 2027 capital expenditures and ISA.[1]

In December 2022, Hydro One revised the capital expenditure and ISA forecast on a multi-year envelope and OEB-category basis to implement the OEB-approved Settlement Proposal (the "Forecast"). This was the first time Hydro One allocated the impact of the Settlement Proposal to the project and program level. The Forecast is the basis for the Program and Project level variances described in this Capital Performance Report.

2.0 PERFORMANCE AT THE OVERALL ENVELOPE AND OEB CATEGORY LEVEL

Table 1 below presents a breakdown of the actual 2024 capital Distribution expenditures and ISA by OEB investment category and compares them against the Settlement Implementation Forecast. The primary focus of this report is on the Distribution System Access, System Renewal, and System Service categories. The Distribution General Plant category is discussed in the General Plant Capital Performance Report.

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 and p.257-258.

Table 1 - 2024 Distribution Capital Expenditures and ISA[2]

OEB Category	Capital Expenditures – 2024			In-Service Additions – 2024		
	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)
System Access	$253.3	$355.2	$101.8	$254.5	$338.3	$83.8
System Renewal (Excl. AMI 2.0)	$287.0	$381.7	$94.7	$299.6	$380.4	$80.8
System Renewal (AMI 2.0 Only)	$69.5	$54.9	-$14.6	$69.5	$0.0	-$69.5
System Service	$157.2	$164.9	$7.7	$138.3	$142.0	$3.7
General Plant	$182.2	$158.8	-$23.4	$185.5	$144.6	-40.9
Total	**$949.2**	**$1,115.6**	**$166.4**	**$947.4**	**$1,005.3**	**$57.9**

In 2024, Hydro One's distribution capital expenditures were 18% above the OEB-approved amount and ISAs were 6% above the OEB-approved amount. Distribution capital expenditures and ISAs were higher due to System Access expenditures related to an increase in customer connection requests, more complex connection projects, and mandatory Joint Use and Relocation work (Externally Driven Work). In addition, accelerated System Renewal investments were completed to comply with polychlorinated biphenyls (PCBs) environmental regulations, respond to major weather events and complete pole replacements. Furthermore, expenditure variances at the OEB-category level were impacted by inflationary pressures including rising costs of goods, services, and labour. Hydro One has responded to these circumstances by reprioritizing and re-pacing its capital portfolio where it was possible to do so.

To partly offset these increases in the System Access category (i.e., customer driven), and the System Renewal category (i.e., compliance and demand driven), Hydro One made reductions in System Renewal (i.e. sustainment and replacement) and System Service (i.e., energy storage solutions and system capacity) categories. Further, lower General Plant and AMI 2.0 expenditures helped mitigate these increases. The OEB categories and associated variance explanations are summarized below.

[2] Does not include Hydro One affiliates.
[3] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.257-58 (Table 25 and 26)

System Access: System Access capital expenditures and ISAs were higher than the OEB-approved amount by $101.8M and $83.8M respectively. These variances were primarily driven by a higher volume of New Load Connections and Service Upgrades (D-SA-02), including more complex large connection projects. As a result of their increased complexity and scope, these projects had higher design and estimation costs. In addition, there were more line relocations and third-party attachment requests. Higher expenditures in the above investments were partly offset by lower expenditures in metering sustainment (D-SA-04) due to lower volume.

System Renewal: System Renewal capital expenditures and ISAs were higher than the OEB-approved amount by $80.1M and $11.3M respectively. These variances were primarily driven by incremental expenditures in Distribution Lines Storm Damage & Trouble Call Response (D-SR-05) as a result of higher incident volumes, PCB equipment replacement (D-SR-06) to comply with environmental regulations, Wood pole program (D-SR-07) due to higher costs, and the Distribution Stations demand program (D-SR-01) driven by higher equipment failures. To mitigate these impacts, Hydro One reprioritized Submarine Cable Replacement (D-SR-09), Sustainment Initiatives (D-SR-10), and Wood pole programs (D-SR-07) volumes. The pace of the Advanced Meter Infrastructure (AMI 2.0) project (D-SR-12) was also adjusted as described further in Section 5 below.

System Service: Capital expenditures and ISAs were higher than the OEB-approved amount by $7.7M and $3.7M respectively. These variances were primarily driven by incremental expenditures in Demand Investments (D-SS-03) and Worst Performing Feeders (D-SS-05). Higher expenditures were partly offset by deferring work in Energy Storage Solutions (D-SS-04) related to grid-connected energy storage projects, and Load Growth projects (D-SS-01) related to system capability reinforcement.

3.0 PERFORMANCE AT THE PROJECT AND PROGRAM LEVEL

Hydro One's Distribution expenditures consist of programs and projects. Programs involve work that is repeatable in nature on a specific asset type that reoccurs every year and the assets are largely in-serviced in the same fiscal year. Projects are stand-alone jobs with a discrete beginning and end which may span over more than one fiscal year and are not in-serviced until they are energized. Capital expenditure variances at the program-level are discussed in Section 4.0, and project-level variances are discussed in Section 5.0.

The projects and programs discussed in this report represent 99% of the 2024 actual ISA that is shown in Table 1 (for the System Access, System Renewal and System Service categories) and as such provide a very strong indication of the overall portfolio performance.

PERFORMANCE DEFINITIONS

Projects and programs with planned or actual ISA in 2024 greater than or equal to $3M have been summarized in the following sub-sections along with variance explanations. The thresholds used by Hydro One to identify "material variances" were determined using the following criteria[4]:

- **Cost Variances** – Material cost variances were identified where the in-year variance in cost for programs, or the total project end cost variance is greater than or equal to $1M and greater than or equal to 10% of planned values.
- **Scope Variances** – For programs, material scope variances arise if the functional scope changes by +/-20% or more.
- **Date Variances** – Material date variances were identified for projects where the actual or projected in-service year shifted from 2024 or earlier, to a later year.

The reasons for variances in individual projects and programs fall into four categories: 1) Emergent Needs, 2) Execution Factors, 3) Work Definition, and 4) Reprioritization. These categories are used to identify the reasons for variances at the project and program level and are defined below.

Emergent Needs

Emergent needs are investments that Hydro One made in response to a change of priority due to equipment condition or failure, as well as customer needs.

Execution Factors

Execution factors represent advances or delays encountered during the execution phase of work which can include timing changes that arise as a result of changing conditions, risks, and priorities that need to be addressed during execution. As risks materialize, plans

[4] This report's variance criteria conform with Hydro One's internal variance reporting criteria which focuses on projects and programs with positive variances greater than the thresholds described below.

are adjusted to accommodate the change and mitigate the overall impact to cost, schedule, and resources. This can change the year in which the project goes in-service without necessarily materially changing the in-service amount or affecting the overall volume of work completed. Some of the main causes of delays are outage deferrals or cancellations, material delivery and logistics factors, as well as customer needs.

Work Definition

Work definition variances arise from the process of refining a project's scope, estimated budget and schedule as the project moves from the high-level planning phase to design and estimate, and execution phases. As the project is refined, there may be increases or decreases in project cost as a result of new or changing information that becomes known during the design and estimation phase or in the execution stage of work.

Reprioritization

Reprioritization includes investments that are accelerated or deferred. Hydro One adjusts its capital investments through annual planning and in-year redirection processes.

4.0 PROGRAM PERFORMANCE

A large portion of Distribution's capital work program includes investments that are driven by demand and require action in a specified period as part of Hydro One's obligations under the Distribution System Code. While Hydro One makes every effort to work within its budget, there are times when an influx of demand work results in a reprioritization of resources away from planned work. Hydro One has a robust redirection process that provides the flexibility necessary to reprioritize investments to respond to fluctuations in emergent work while aiming to minimize the impacts of deferring planned investments that can introduce additional risks to the system in future years. Distribution Capital Program variances are summarized in Table 2 and further discussed below.

Table 21 - Distribution Program Summary

			2024 Dx Capital Expenditures ($M)			2024 Dx In-Service Additions ($M)			2024 Dx Units				Performance
OEB Category	Program Description		Forecast	Actual	Variance	Forecast	Actual	Variance	Unit Description	Forecast	Actual	Variance	Variance Category
System Access	D-SA-01	Joint Use and Relocations	30.7	45.1	14.3	31.2	38.8	7.7	None	n/a	n/a	n/a	Emergent Needs
	D-SA-02	New Load Connections and Upgrades	162.7	267.9	105.2	162.7	258.7	96.1	# of Connections, & Upgrades	21,178	24,832	3,654	Work Definition
	D-SA-04	Metering Sustainment	49.7	38.4	-11.3	49.7	38.8	-10.9	# of Meters Replaced	73,074	59,682	-13,392	Work Definition
System Renewal	D-SR-01	Distribution Stations Demand Capital Program	6.6	15.0	8.4	6.5	19.1	12.6	None	n/a	n/a	n/a	Emergent Needs
	D-SR-02	Mobile Unit Substation Program	4.5	3.2	-1.3	4.8	3.9	-0.9	# of MUS	2	1	-1	Reprioritization
	D-SR-03	Distribution Station Planned Component Replacement Program	4.4	5.2	0.8	4.6	4.9	0.3	# of Recloser & MUS Structures	139	103	-36	Execution Factors
	D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	113.8	168.5	54.7	113.8	168.3	54.5	None	n/a	n/a	n/a	Emergent Needs
	D-SR-06	Distribution Lines PCB Equipment Replacement Program	9.9	38.0	28.1	9.9	37.8	27.9	# of Transformer Replacements	1,504	2,903	1,399	Execution Factors
	D-SR-07	Pole Replacement	59.8	85.4	25.6	59.8	84.9	25.1	# of Pole Replacements	6,009	4962	-1,047	Execution Factors
	D-SR-07	Wood Pole Test and Treat	10.6	14.5	3.8	10.6	13.5	2.9	# of Poles Tested	101,597	116,682	15,085	Emergent Needs
	D-SR-07	Wood Pole Structural Refurbishment	6.6	7.5	0.9	6.6	7.5	0.9	# of Poles Refurbished	2,794	4,217	1,423	Emergent Needs
	D-SR-08	Distribution Lines Minor Component Replacement Program	15.3	14.0	-1.3	14.8	14.0	-0.8	# of Components Replaced	3,459	5,152	1,693	Work Definition
	D-SR-09	Submarine Cable Replacement Program	13.1	6.4	-6.7	13.1	6.2	-6.9	None	n/a	n/a	n/a	Reprioritization
	D-SR-10	Distribution Lines Sustainment Initiatives	8.4	4.4	(4.0)	8.3	4.9	-3.4	None	n/a	n/a	n/a	Reprioritization
System Service	D-SS-03	Demand Investments	14.1	24.0	9.9	14.0	19.4	5.5	None	n/a	n/a	n/a	Emergent Needs
	D-SS-04	Energy Storage Solutions	30.4	11.0	-19.4	28.1	9.7	-18.4	# of Battery Systems Installed	n/a	450	n/a	Reprioritization
	D-SS-05	Worst Performing Feeders	37.0	46.3	9.3	36.9	44.1	7.3	# of Devices	1,028	1,230	202	Work Definition
	D-SS-06	Stray Voltage	4.1	7.0	3.0	4.1	6.9	2.8	None	n/a	n/a	n/a	Emergent Needs

4.1 SYSTEM ACCESS PROGRAMS

The **Joint Use and Lines Relocations (D-SA-01)** program expenditures were above the forecast largely due to continued higher volumes of work, increased complexity in large line relocation projects, and the rising cost pressures outlined in Section 2.0 above. Hydro One is required to meet contractual obligations to third parties through Joint Use agreements and to maintain compliance with Hydro One's distributor licence.

The **New Load Connection, Upgrades, Cancellations (D-SA-02)** program expenditures were above the forecast as the volume and scope of customer connections in 2024 materially exceeded historical levels. Hydro One facilitated a higher volume of large connection requests, which are more complex and costly to design and construct. In addition, expenditures for this program were affected by the general cost pressures outlined in Section 2.0 above. While there has been growth in both the volume and size of residential subdivision projects, the corresponding connection volumes will materialize in future periods. This is due to a timing lag as residential owners connect to the distribution system, over time.

The **Meter Infrastructure Sustainment (D-SA-04)** program expenditures were below the forecast largely due to a lower than forecast meter failures. As a result, fewer meters were replaced than initially projected.

4.2 SYSTEM RENEWAL PROGRAMS

The **Distribution Stations Demand Capital (D-SR-01)** program expenditures were above the forecast due to emergent needs driven by higher equipment failures. Costs in this category will vary depending on the type of failure, which can range from individual component replacements such as failed switches or electronic reclosers, to failed transformer replacements. This program was also affected by the rising cost pressures outlined in Section 2.0 above.

The **Mobile Unit Substations (D-SR-02)** program expenditures were below the forecast as it was reprioritized and deferred to future years. The 2024 expenditures and accomplishment were mostly carryover work from 2023.

The **Distribution Station Planned Component Replacement (D-SR-03)** program expenditures were in line with the forecast, however unit accomplishments were below forecast. Expenditures were higher due to technical constraints including unplanned yard extensions to accommodate required equipment, and unplanned battery/charger replacements.

The **Distribution Lines Trouble Call and Storm Damage Response (D-SR-05)** program expenditures were above the forecast due to a higher volume of storm damage, and trouble call related equipment failures and replacement requirement, in addition to higher general cost pressures outlined in Section 2.0. Major weather events including storms in April, June and November impacted program expenditures.

The **Distribution Lines PCB Equipment Replacement Program (D-SR-06)** program expenditures exceeded the forecast as Hydro One completed work to replace equipment containing PCBs to meet deadlines associated with environmental regulations. Replacement costs were also higher as certain associated equipment was replaced/upgraded at the same time, such as the pole in addition to the PCB-filled transformer.

The **Pole Sustainment Program (D-SR-07)** program contains three sub-programs: Pole Replacement, Wood Pole Test and Treat, and Wood Pole Structural Refurbishment. Pole Replacement expenditures were above forecast largely due to cost pressures as outlined in Section 2.0. As a result, some pole replacement work was deferred. To balance reliability risk associated with this deferral, Hydro One increased expenditures and accomplishments in both the Pole Test and Treat and Pole Refurbishment programs, resulting in lower refurbishment unit costs due to execution efficiencies.

The **Distribution Lines Minor Component Replacement Program (D-SR-08)** program expenditures were slightly below the forecast as a higher volume of less expensive components were replaced, such as crossarms and sentinel lights, resulting in higher accomplishments than forecast.

The **Submarine Cable Replacement Program (D-SR-09)** program expenditures were below the forecast due to work reprioritization to mitigate cost pressures in other programs. Severely degraded cables were prioritized and replaced to mitigate public safety risks.

The **Distribution Lines Sustainment Initiatives (D-SR-10)** program expenditures were below the forecast due to work reprioritization to mitigate emergent needs and cost pressures in other programs.

4.3 SYSTEM SERVICE PROGRAMS

The **Demand Investments (D-SS-03)** program expenditures were above the forecast due to higher than anticipated investment needs to address localized load growth and system constraints. This work includes minor distribution system modifications that are necessary and urgent to address system needs identified by customer power quality complaints, feeder studies and system impact assessments.

The **Energy Storage Solutions (D-SS-04)** program expenditures were below the forecast mostly due to reprioritization of work. Grid-scale battery energy storage projects were deferred to respond to emergent needs and cost pressures in other programs. Behind-the-meter residential battery storage for Customers Experiencing Long Interruption Duration (CELID) was prioritized to address localized reliability improvements.

The **Worst Performing Feeders Program (D-SS-05)** program expenditures were above the forecast to support the installation of a higher volume of Switches and Communicating

Fault Current Indicators (CFCI) devices on poor performance feeders. These investments were prioritized to improve reliability for customers and mitigate safety risks.

The **Stray Voltage (D-SS-06)** program expenditures were above the forecast due to higher requirements to address customer reported stray voltage and power quality issues.

5.0 PROJECT PERFORMANCE

The Distribution capital envelope is largely program-based, however, some large System Service investments are required to ensure the system can accommodate load growth. For these projects, Hydro One focuses on adherence to the total project cost rather than adherence to in-year expenditures

Table 3 summarizes the projects that met the performance criteria of a material variance for either timing, scope or cost with detailed explanations for each listed below.

As the Distribution capital work program is largely comprised of programs and smaller projects, few projects meet the $3M variance threshold. Hydro One continues to manage its capital expenditures through its investment planning process which prioritizes investments that respond to mandatory service obligations and mitigate the highest risk for the lowest cost. The balance of risks, system needs, and capital requirements that underpin a project deferral will continue to be monitored and reprioritized in conformance with the investment planning process.

The 19 projects in Table 3 below are either in a Planning, Deferred, Execution, or Completed phase. Of these 19 projects 3 did not meet the performance definitions in Section 3.1 above, 2 were reprioritized or cancelled primarily due to load growth materializing at a slower than forecast pace. Another 5 were reprioritized to accommodate projects or programs requiring emergent needs. Variance explanations for the remaining 9 projects have been provided where required using the criteria outlined in Section 3.1 above.

Table 3 - Distribution Project Summary

			2024 Dx Capital Expenditures ($M)		2024 Dx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[5]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance	Variance Category
Pointe Au Baril Transformer Replacement	Execution	D-SR-04	2.0	0.7	4.1	3.6	4.1	3.5	-0.6	2024	2024	0	Not Applicable
Lindsay M7 Line Upgrade	Execution	D-SR-10	5.0	7.5	11.0	10.8	11.0	11.1	0.1	2024	2024	0	Not Applicable
Norfolk M3 Tillsonburg M10 Tie Relocation	Planning	D-SR-10	3.2	0.0	3.6	0.0	3.6	3.6	0.0	2024	2028	4	Reprioritization
AMI 2.0	Execution	D-SR-12	69.5	54.9	111.2	0.0	705.6	820.0	114.4	2029	2029	0	Execution Factors
Barrie TS - Construct new feeders	Execution	D-SS-01	2.8	6.4	8.4	0.0	8.4	11.0	2.6	2024	2025	1	Execution Factors
Brockville 44kV Load Growth	Planning	D-SS-01	4.5	0.0	9.9	0.0	9.9	9.9	0.0	2024	2030	6	Reprioritization
Caledonia TS New Feeder Positions	Execution	D-SS-01	3.0	3.4	3.0	0.0	3.0	5.9	2.9	2024	2025	1	Work definition
Curve Inn DS New Feeder	Execution	D-SS-01	0.0	0.6	0.0	4.2	5.6	4.2	-1.4	2023	2024	1	Execution Factors
Greens Corner and Vittoria PDS	Planning	D-SS-01	2.0	0.0	3.0	0.0	3.0	3.0	0.0	2024	2029	5	Reprioritization
Kirkland Lake Voltage Conversion - Part 3	Planning	D-SS-01	3.1	0.3	3.3	0.0	3.3	3.3	0.0	2024	2026	2	Reprioritization
Listowel Load Relief - Load Growth	Planning	D-SS-01	3.7	0.0	4.3	0.0	4.3	4.3	0.0	2024	2028	4	Execution Factors
Manotick DS Add F3 Feeder Load Growth	Cancelled	D-SS-01	2.8	0.0	3.0	0.0	3.0	0.0	-3.0	2024	n/a	n/a	Not Applicable
Saugeen Shores DS and Port Elgin Load Growth	Planning	D-SS-01	2.0	0.1	5.4	0.0	5.4	5.4	0.0	2024	2026	2	Reprioritization
South Middle Road TS DESN1 Feeder Development	Execution	D-SS-01	1.2	3.2	0.0	21.4	130.5	141.4	10.9	2025	2025	0	Not Applicable
Stouffville 10th Line DS to Ringwood DS 27.6kV Tie	Execution	D-SS-01	0.7	2.9	1.5	3.9	1.5	3.9	2.4	2024	2024	0	Emergent Needs
Wikwemikong Supply - Station & Line Work	Execution	D-SS-01	0.0	5.1	0.0	13.8	6.0	14.2	8.2	2023	2024	1	Execution Factors
Muskoka TS M1-M5 New Tie Line	Planning	D-SS-02	10.1	0.1	10.2	0.0	10.2	10.2	0.0	2024	2030	6	Reprioritization
Orillia TS M2-M6 New Tie Line	Execution	D-SS-02	4.1	5.5	4.2	5.8	4.2	5.8	1.6	2024	2024	0	Work Definition
Dryden Rural DS F2 1ph to 3ph Conversion	Execution	D-SS-NEW	0.0	4.2	0.0	4.5	0.0	4.8	4.8	0	2024	n/a	Emergent Needs

[5] Phases: Planning, Execution, Complete, Cancelled, or Deferred.

Several factors impacted project costs and schedule:

Vendor Estimates and Municipal Delays: Caledonia TS New Feeder and Feeder Positions (D-SS-01), and Listowel Load Relief (D-SS-01) projects are all in early stages of development. The Caledonia projects experienced delays in obtaining detailed estimates from vendors. The Listowel project experienced delays in approvals from the local municipality. Coordination with other municipal work resulted in cost savings for the Curve Inn DS New Feeder (D-SS-01) project while accommodating a longer in-servicing schedule.

Scope Modifications During Detailed Design: Design adjustments to accommodate community requests and additional requirements uncovered during detailed design increased project scope for the Wikiwemikong Supply – Station & Line Work (D-SS-01), Barrie TS – New Feeders (D-SS-01), and Orillia TS M2-M6 New Tie Line projects (D-SS-02).

Project Changes to Address Emerging Reliability Constraints: Areas such as Wabigoon First Nation and the Town of Stouffville experienced higher than anticipated load growth and potential reliability constraints. Hydro One addressed these constraints by prioritizing and adjusting the scopes for Stouffville 10th Line DS to Ringwood DS 27.6 kV Tie (D-SS-01) and Dryden Rural DS F2 1ph to 3ph Conversion (D-SS-NEW) projects.

AMI 2.0 Project Implementation (D-SR-12): Total costs in the AMI 2.0 project have increased primarily due to higher than estimated IT integration, foundational planning and program management activities (e.g., contracting, IT assessments and IT development work) associated with complexities moving from the AMI 1.0 to the AMI 2.0 platform. As a result of these challenges, the meter and network deployment pilot has been rescheduled to 2025. Hydro One remains focused on managing the AMI 2.0 capital envelope in the current rate period and identifying efficiencies to mitigate the cost variances and schedule delays experienced to date.

Section 2.3

2024 General Plant Capital Performance Report

GENERAL PLANT CAPITAL PERFORMANCE REPORT – 2024

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Performance Report provides an overview of Hydro One's performance in 2024 in relation to the overall General Plant capital envelope for the year and reviews the performance of individual projects and programs. It addresses both capital expenditures and in-service additions (ISA) delivered by Hydro One, organized as follows:

This report consists of two sections:

- Section 2 presents Transmission-allocated General Plant investments
- Section 3 presents Distribution-allocated General Plant investments

1.2 APPROVED CAPITAL INVESTMENT

In Hydro One's application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached settlement with all parties (the Settlement Proposal) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, the OEB approved Hydro One's 2023 to 2027 capital expenditures and ISA.[1]

In December 2022, Hydro One revised the capital expenditure and ISA forecast on a multi-year envelope and OEB-category basis to implement the OEB-approved Settlement Proposal (the "Forecast"). This was the first time Hydro One allocated the impact of the Settlement Proposal to the project and program level. The Forecast is the basis for the Program and Project level variances described in this Capital Performance Report.

1.3 PERFORMANCE DEFINITIONS

Projects and programs with planned or actual ISA in 2024 greater than or equal to $3M have been summarized in the tables below along with variance explanations. The

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 and p.257-258.

thresholds used by Hydro One to identify “material variances” were determined using the following criteria[2]:

- **Cost Variances** – Material cost variances were identified where the in-year variance in cost for programs, or the total project end cost variance is greater than or equal to $1M and greater than or equal to 10% of planned values.
- **Scope Variances** – For programs, material scope variances arise if the functional scope changes by +/-20% or more.
- **Date Variances** – Material date variances were identified for projects where the actual or projected in-service year shifted from 2024 or earlier to a later year.

The variance in these major projects and programs fall mainly into four categories: 1) Emergent Needs, 2) Execution Factors, 3) Work Definition, and 4) Reprioritization. These categories are used to identify the reasons for variances at the project and program level and are further defined below.

Emergent Needs

Emergent needs are investments that Hydro One made in response to a change of priority due to equipment condition or failure, as well as customer needs.

Execution Factors

Execution factors represent advances or delays encountered during the execution phase of work which can include timing changes that arise as a result of changing conditions, risks and priorities that need to be addressed during execution. As risks materialize, plans are adjusted to accommodate the change and mitigate the overall impact to cost, schedule and resources. This can change the year in which the project goes in-service without necessarily materially changing to the in-service amount or affecting the overall volume of work completed. Some of the main causes of delays are outage deferrals or cancellations, material delivery and logistics factors as well as customer needs.

---

[2] This report’s variance criteria conform with Hydro One’s internal variance reporting criteria which focuses on projects and programs with positive variances greater than the thresholds described below.

Work Definition

Work definition variances arise from the process of refining a project's scope, the estimated budget and schedule as the project moves from the high-level planning phase to design and estimate, and execution phases. As the project is refined, there may be increases or decreases to the project cost as a result of new or changing information that becomes known during the design and estimation phase or in the execution stage of work.

Reprioritization

Reprioritization includes investments that are accelerated or deferred. Hydro One adjusts its capital investments through annual planning and in-year redirection processes.

2.0 TRANSMISSION-ALLOCATED GENERAL PLANT INVESTMENTS

2.1 PERFORMANCE AT THE TRANSMISSION GENERAL PLANT CATEGORY

Table 1 below presents a breakdown of the actual 2024 capital expenditures and ISA for the Transmission General Plant category and compares them against OEB-approved values.

Table 1 - 2024 Transmission Capital Expenditures and ISA[3]

OEB Category	Capital Expenditures – 2024			In-Service Additions – 2024		
	OEB-Approved ($M)[4]	Actual ($M)	Variance ($M)	OEB-Approved ($M)	Actual ($M)	Variance ($M)
General Plant – Tx	$121.4	$126.7	$5.3	$149.6	$115.1	-$34.5

In 2024, Hydro One's Transmission-allocated General Plant capital expenditures were 4% above the OEB-approved amount and ISAs were 23% below the OEB-approved amount. As described below, these variances are mainly driven by Information Solutions program variances, including emergent cybersecurity needs, reprioritization of technology investments, and execution factors such as scope refinement and timeline shifts.

[3] Does not include Hydro One affiliates.
[4] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 (Table 22 and 23)

2.2 PERFORMANCE AT THE TRANSMISSION PROJECT AND PROGRAM LEVEL

This section presents projects and programs with planned or actual ISA greater than or equal to $3M. A variance category is assigned to any project or program with material variances, as described in Section 1.3. Transmission-allocated General Plant programs are presented below in Table 2 and material projects are presented below in Table 3.

2.2.1 TRANSMISSION PROGRAM PERFORMANCE

Transmission-allocated General Plant Program variances are summarized in Table 2 and further discussed below:

Table 2 - Transmission General Plant Program Summary

			2024 Tx Capital Expenditures ($M)			2024 Tx In-Service Additions ($M)			2024 Units[5]				Performance
Category	**EB-2021-0110 ISD Number**	**Program Description**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Unit Description**	**Forecast**	**Actual**	**Variance**	**Variance Category**
Fleet	G-GP-01	Transport and Work Equipment	21.5	21.4	-0.1	21.5	21.4	-0.1	# of vehicles	311	587	276	Execution Factors
Facilities and Real Estate	G-GP-03	Facilities and Accommodation	17.2	21.6	4.3	3.2	1.7	-1.6	N/A	N/A	N/A	N/A	Execution Factors
	G-GP-04	Transmission Facilities	13.4	12.5	-0.9	11.4	13.2	1.8	N/A	N/A	N/A	N/A	Emergent Needs & Reprioritization
Information Solutions	G-GP-05	Hardware/Software Refresh and Maintenance	6.5	10.4	3.8	6.8	13.2	6.5	N/A	N/A	N/A	N/A	Emergent Needs
	G-GP-10	Physical Security Upgrade	8.4	8.3	-0.2	2.2	7.3	5.1	N/A	N/A	N/A	N/A	Reprioritization
	G-GP-11	Security Monitoring	7.5	4.2	-3.3	7.0	5.1	-2.0	N/A	N/A	N/A	N/A	Reprioritization
System Operations	G-GP-12	Common Operating Technology Infrastructure	3.0	3.1	0.1	3.1	4.6	1.6	N/A	N/A	N/A	N/A	Execution Factors
Operating Infrastructure	G-GP-19	Grid Control Network Sustainment	6.1	5.3	-0.8	6.0	4.0	-2.0	N/A	N/A	N/A	N/A	Execution Factors

[5] Where the cost allocation of the program is shared between Transmission and Distribution, the unit numbers reflect the total units allocated to both Transmission and Distribution for the respective investment.

The **Transport and Work Equipment (G-GP-01)** program had expenditures that were in line with the forecast. The program's unit variance was due to more light-duty vehicles (and fewer heavy-duty vehicles) being replaced than planned due to delays from the manufacturers.

The **Facilities and Accommodation (G-GP-03)** program had capital expenditures that were above the forecast and ISAs that were below forecast. The variance is primarily due to increased material and construction costs driven by design updates of the Orillia Warehouse new build project, which is expected to go into service in 2025 resulting in a net decrease in 2024 ISAs.

The **Transmission Facilities (G-GP-04)** program had capital expenditures that were slightly below the forecast and ISAs that were above forecast. The variance is due to work reprioritization to complete several smaller repair projects to mitigate emerging health and safety concerns and maintain operations in the transmission facilities, which led to the deferral of a new build project.

The **Hardware/Software Refresh and Maintenance (G-GP-05)** program had capital expenditures and ISAs that were above the forecast. The variance is due to several emerging program needs, including increased purchase of minor fixed assets to address end-of-life laptops and tablets, incremental costs to purchase additional licenses for identity access management and other systems as required to maintain cybersecurity, legal and privacy compliance.

The **Physical Security Upgrade (G-GP-10)** program's capital expenditures were consistent with the forecast, while ISAs exceeded the forecast. The ISA variance is due to the reprioritization of smaller projects that could be in-serviced within the same year as construction. The plan was adjusted based on threat risk assessment results and the opportunity to leverage concurrent construction activities in the same region.

The **Security Monitoring (G-GP-11)** program had capital expenditures and ISAs that were below the forecast due to the reprioritization of some investments, while continuing to address emergent cybersecurity risks.

The **Common Operating Technology Infrastructure (G-GP-12)** program had ISAs that were above the forecast due to the purchase of long-lead time hardware in 2023.

The **Grid Control Network Sustainment (G-GP-19)** program had capital expenditures and ISAs that were below the forecast. The variance is due to equipment delivery delays from manufacturers and the removal of one site from scope as it was no longer required.

2.2.2 TRANSMISSION PROJECT PERFORMANCE

Transmission-allocated General Plant Project variances are summarized in Table 3 and further discussed below:

1 **Table 3 - Transmission General Plant Project Summary**

				2024 Tx Capital Expenditures ($M)		2024 Tx In-Service Additions ($M)		Project End Total Cost ($M)[6]			In-Service Year			Performance
Functional Area / Project Name	**Allocation**	**Project Phase[7]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance (Years)**	**Variance Category**
System Operations														
NMS Upgrade Project	Transmission	Complete	G-GP-16	0.0	6.3	0.0	25.0	38.0	46.0	8.0	2023	2024	1	Execution Factors
Operating Infrastructure														
Geomagnetically Induced Currents (GIC) Monitoring Installation	Transmission	Deferred	G-GP-Other	0.8	0	3.8	0	3.8	1.8	-2.0	2024	2026	2	Execution Factors

[6] Where the cost allocation of the project is shared, the project total reflects the total value allocated to both Transmission and Distribution for the respective investment.
[7] Phases: Planning, Execution, Complete, Cancelled, or Deferred.

The **NMS Upgrade Project (G-GP-16)** had capital expenditures and ISAs that were above the forecast. During project execution, incremental modeling improvements and testing resources were required to address data-related application issues affecting the state estimator. The additional effort resulted in deferred ISAs from 2023 into 2024.

The **GIC Monitoring Installation (G-GP-Other)** was deferred as the vendor discontinued the original equipment and replaced it with a new model. This equipment is essential for monitoring geomagnetic disturbances on transmission lines. To ensure the new equipment meets performance expectations, multi-year testing is being conducted prior to broader installation.

3.0 DISTRIBUTION-ALLOCATED GENERAL PLANT INVESTMENTS

3.1 PERFORMANCE AT THE DISTRIBUTION GENERAL PLANT CATEGORY

Table 4 below presents a breakdown of the actual 2024 capital expenditures and ISA for the Distribution General Plant category and compares them against the OEB-approved values.

Table 4 - 2024 Distribution Capital Expenditures and ISA[8]

OEB Category	Capital Expenditures – 2024			In-Service Additions – 2024		
	OEB-Approved ($M)[9]	Actual ($M)	Variance ($M)	OEB-Approved ($M)	Actual ($M)	Variance ($M)
General Plant - Dx	$182.2	$158.8	-$23.4	$185.5	$144.6	-$40.9

In 2024, Hydro One's Distribution-allocated General Plant capital expenditures were13% below the OEB-approved amount and ISAs were 22% below the OEB-approved amount. As described below, these variances are mainly driven by Information Solutions and System Operations project variances, including emergent cybersecurity needs and reprioritization of digital investments.

3.2 PERFORMANCE AT THE DISTRIBUTION PROJECT AND PROGRAM LEVEL

This section presents projects and programs with planned or actual ISA greater than or equal to $3M. A variance category is assigned to any project or program with material variances, as described in Section 1.3. Distribution-allocated General Plant programs are presented below in Table 5 and material projects are presented below in Table 6.

3.2.1 DISTRIBUTION PROGRAM PERFORMANCE

Distribution-allocated General Plant Program variances are summarized in Table 5 and further discussed below:

---

[8] Does not include Hydro One affiliates.
[9] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.257-58 (Table 25 and 26)

1 **Table 5 - Distribution General Plant Program Summary**

			2024 Dx Capital Expenditures ($M)			2024 Dx In-Service Additions ($M)			2024 Units[10]				Performance
Category	**EB-2021-0110 ISD Number**	**Program Description**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Unit Description**	**Forecast**	**Actual**	**Variance**	**Variance Category**
Fleet	G-GP-01	Transport and Work Equipment	42.1	42.0	-0.1	42.1	42.0	-0.1	# of vehicles	311	587	276	Execution Factors
	G-GP-02	Helicopters	3.9	5.0	1.0	3.9	5.0	1.1	# of helicopters	1	1	0	Emergent Needs
Facilities and Real Estate	G-GP-03	Facilities and Accommodation	83.5	76.6	-7.0	32.7	35.6	2.9	N/A	N/A	N/A	N/A	Not Applicable
Information Solutions	G-GP-05	Hardware/Software Refresh and Maintenance	11.2	16.8	5.6	11.5	20.7	9.2	N/A	N/A	N/A	N/A	Emergent Needs
	G-GP-11	Security Monitoring	8.8	4.5	-4.2	8.2	5.7	-2.4	N/A	N/A	N/A	N/A	Reprioritization
System Operations	G-GP-12	Common Operating Technology Infrastructure	4.1	4.2	0.1	4.2	6.3	2.1	N/A	N/A	N/A	N/A	Execution Factors

[10] Where the cost allocation of the program is shared between Transmission and Distribution, the unit numbers reflect the total units allocated to both Transmission and Distribution for the respective investment.

The **Transport and Work Equipment (G-GP-01)** program had expenditures that were in line with the forecast. Please see the unit variance explanation provided in Section 2.2.1.

The **Helicopters (G-GP-02)** program had capital expenditures and ISAs that were above the forecast. The higher-than-expected spending was primarily driven by an unplanned helicopter engine overhaul required to continue operating the asset.

The **Hardware/Software Refresh and Maintenance (G-GP-05)** program had capital expenditures and ISAs that were above the forecast. Please see the explanation provided in Section 2.2.1.

The **Security Monitoring (G-GP-11)** program had capital expenditures and ISAs that were below the forecast. Please see the explanation provided in Section 2.2.1.

The **Common Operating Technology Infrastructure (G-GP-12)** program had ISAs that were above the forecast. Please see explanation provided in Section 2.2.1.

3.2.2 DISTRIBUTION PROJECT PERFORMANCE

Distribution-allocated General Plant Project variances are summarized in Table 6 and further discussed below:

1 **Table 6 - Distribution General Plant Project Summary**

				2024 Dx Capital Expenditures ($M)		2024 Dx In-Service Additions ($M)		Project End Total Cost ($M)[11]			In-Service Year			Performance
Functional Area / Project Name	**Allocation**	**Project Phase[12]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Project Total Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Variance Category**
Information Solutions														
Customer Digital Experience Journey	Distribution	Deferred	G-GP-07 & G-GP-Other	17.6	0.0	9.7	0.0	32.2	32.2	0	2023	2032	9	Reprioritization
Itron Enterprise Edition (IEE) Upgrade	Distribution	Complete	G-GP-08	0.0	2.8	0.0	8.0	1.2	8.0	6.8	2023	2024	1	Work Definition
Net Metering Regulatory Compliance	Distribution	Complete	G-GP-NEW	0.0	2.7	0.0	3.9	0.0	3.9	3.9	-	2024	-	Emergent Needs
System Operations														
ORMS Upgrade	Distribution	Cancelled	G-GP-17	4.3	0.0	8.5	0.0	8.5	0.0	-8.5	2024	-	-	Work Definition
DMS	Distribution	Cancelled	G-GP-18	2.7	0.0	5.4	0.0	5.4	0.0	-5.4	2024	-	-	Work Definition

[11] Where the cost allocation of the project is shared, the project total reflects the total value allocated to both Transmission and Distribution for the respective investment.
[12] Phases: Planning, Executing, Complete, Cancelled, or Deferred.

The **Customer Digital Experience Journey (G-GP-07 & G-GP-Other)** project had expenditures that were below the forecast as it was deferred due to work reprioritization.

The **Itron Enterprise Edition (IEE) Upgrade (G-GP-08)** project had expenditures that were above the forecast due to scope changes identified during the discovery phase. This increased the level of effort and extended the project timeline. The upgrade is essential to ensure continued vendor support, cybersecurity protection, and accurate billing.

The **Net Metering Regulatory Compliance (G-GP-NEW)** is a new project**.** This project was required to implement changes in customer processes, ensuring that net-metered Regulated Price Plan (RPP) customers could choose pricing plan options, as directed by the OEB.

The **ORMS Upgrade (G-GP-17)** project was cancelled based on Hydro One’s decision to pursue a single Advanced Distribution Management System (ADMS).

The **DMS (G-GP-18)** project was cancelled based on Hydro One’s decision to pursue a single ADMS.

Section 3.1

DERs Connected to Hydro One's Distribution System (per undertaking JT-3.22)

Number and MW of Behind the Meter Distributed Energy Resources Connected to Hydro One Feeders by Fuel Type - 2024

The breakdown of behind-the-meter Distributed Energy Resources (BTM DER) connected to Hydro One Networks Inc.'s (Hydro One) distribution system by transmission station as of December 31, 2024 is as follows:

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
AGUASABON DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
ALLANBURG TS	22.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.00	0.19
ALLISTON TS	5.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	2.00	18.24	7.00	18.36
ALMONTE TS	57.00	0.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.00	0.63
ARDOCH DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
ARMITAGE TS DESN1	24.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.50	25.00	0.68
ARMITAGE TS DESN2	31.00	0.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.86
ARNPRIOR TS	52.00	0.56	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	55.00	0.59
AWENDA DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
AYLMER TS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	7.00	0.07
BARRIE TS	1.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.20
BATTERSEA DS	12.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.12
BEAMSVILLE TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
BEAVERTON TS	48.00	0.52	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.00	0.53
BELLE RIVER TS	10.00	0.12	1.00	0.01	0.00	0.00	0.00	0.00	1.00	0.03	12.00	0.15
BELLEVILLE TS	59.00	1.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.00	1.50
BILBERRY CREEK TS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
BIRCH TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.98	2.00	3.98
BLOOMSBURG DS	17.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	0.20
BRACEBRIDGE TS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
BRANT TS	20.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02	22.00	0.19

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
BRANTFORD TS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02
BROCKVILLE TS	61.00	1.86	0.00	0.00	0.00	0.00	0.00	0.00	3.00	3.60	64.00	5.46
BROWN HILL TS	70.00	0.60	2.00	0.01	0.00	0.00	0.00	0.00	2.00	0.64	74.00	1.25
BUCHANAN TS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	3.00	14.27	9.00	14.33
BURLEIGH DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CALEDONIA TS	20.00	0.23	4.00	0.01	0.00	0.00	0.00	0.00	2.00	4.00	26.00	4.24
CENTRALIA TS	18.00	1.28	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04	22.00	1.32
CHAPLEAU DS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.80	1.00	1.80
CHESTERVILLE TS	28.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.00	0.33
CLARABELLE TS	19.00	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.00	0.29
CLARENCE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CLARKE TS	19.00	0.45	0.00	0.00	0.00	0.00	0.00	0.00	4.00	10.46	23.00	10.91
CLEARWATER BAY DS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
COBDEN DS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
COBDEN TS	27.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.12	39.00	0.32
COCHRANE WEST DS	7.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.30
COMMERCE WAY TS	17.00	0.65	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.50	18.00	3.15
CONSTANCE DS	8.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	9.00	0.14
CRAIG DS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
CRAWFORD TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.79	1.00	0.79
CROSBY TS DESN1	14.00	0.23	1.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04	19.00	0.27
CROWLAND TS	8.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.06
CRYSTAL FALLS TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
CUMBERLAND DS	12.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.11
DES JOACHIMS DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	2.00	0.02

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
DOBBIN DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
DOBBIN TS	64.00	0.60	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.50	65.00	3.10
DOUGLAS POINT TS	32.00	0.87	1.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	33.00	1.11
DRYDEN TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
DUART TS DESN1	12.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.34
DUNDAS TS	41.00	0.73	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.23	44.00	0.96
DUNNVILLE TS	22.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.04	25.00	0.38
DYMOND TS	5.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.07	7.00	3.13
EDGEWARE TS	49.00	0.93	0.00	0.00	0.00	0.00	0.00	0.00	3.00	11.10	52.00	12.03
ELMIRA TS	2.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.30	3.00	2.35
ENFIELD TS DESN 1	12.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.52	13.00	0.65
ESPANOLA TS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
ETON DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
EVERETT TS	18.00	0.34	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	19.00	0.35
FAUQUIER DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
FERGUS TS	106.00	1.59	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.04	108.00	1.63
FOREST JURA DS	18.00	0.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.00	0.56
FOREST LEA DS	8.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.07
FRONTENAC TS	48.00	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.00	0.61
GALT TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
GODERICH TS	5.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	6.00	0.17
GRAND BEND EAST DS	7.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.11
GREELY DS	32.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.00	0.31
HANOVER TS	75.00	0.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	75.00	0.86
HARROWSMITH DS	23.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.00	0.19

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
HAVELOCK TS	40.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	7.00	4.06	47.00	4.39
HAWTHORNE TS	40.00	0.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.00	0.41
HEARST TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
HERRIDGE LAKE DS	2.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	5.00	0.18
HIGHBURY TS	12.00	0.22	0.00	0.00	0.00	0.00	0.00	0.00	2.00	6.00	14.00	6.21
HINCHINBROOKE DS	5.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05	10.00	0.08
HOLLAND TS	14.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.36
HOYLE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
INGERSOLL TS	30.00	1.37	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.14	44.00	1.51
JARVIS TS	18.00	0.49	2.00	0.01	0.00	0.00	0.00	0.00	4.00	0.03	24.00	0.53
KAPUSKASING TS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.16	3.00	0.17
KEEWATIN DS	9.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.08
KEITH TS DESN1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3.40	1.00	3.40
KENORA DS	16.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.13
KENT TS DESN1	15.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	1.00	5.00	16.00	5.36
KENT TS DESN2	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	3.00	2.40	6.00	2.43
KINGSTON GARDINER TS DESN1	52.00	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.00	0.44
KINGSTON GARDINER TS DESN2	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	2.00	16.80	3.00	16.81
KINGSVILLE TS	16.00	0.37	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.82	17.00	1.19
KIRKLAND LAKE TS	8.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08
KLEINBURG TS	56.00	0.80	1.00	0.01	0.00	0.00	0.00	0.00	4.00	4.63	61.00	5.44
LAFOREST ROAD DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
LAMBTON TS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
LARCHWOOD TS	7.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04	11.00	0.11
LAUZON TS DESN1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.95	1.00	0.95

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
LAUZON TS DESN2	6.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.75	7.00	1.06
LDC Owned Station	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
LEAMINGTON TS DESN 1	10.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	1.00	10.00	11.00	10.30
LEAMINGTON TS DESN 2	2.00	0.51	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.82	3.00	1.33
LINDSAY TS	35.00	1.44	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04	39.00	1.48
LODGEROOM DS	14.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.17
LONGLAC TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
LONGUEUIL TS	31.00	0.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.79
LONGWOOD TS	34.00	0.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.00	0.45
MALDEN TS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	1.00	9.20	7.00	9.26
MANITOULIN TS	30.00	0.78	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.79
MANOTICK DS	9.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.08
MARATHON DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MARGACH DS	14.00	0.11	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.12
MARIONVILLE DS	11.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.18
MARTINDALE TS	23.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.07	30.00	0.27
MASSEY DS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
MATTAWA DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	3.00	0.03
MAZINAW DS	72.00	0.67	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.99	73.00	3.66
MEAFORD TS	40.00	0.45	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.75	41.00	1.20
MIDHURST TS DESN1	58.00	0.46	1.00	0.00	0.00	0.00	1.00	0.04	0.00	0.00	60.00	0.50
MINAKI DS	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00
MINDEN TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	25.00	0.25	26.00	0.26
MONTEITH DS	15.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.14
MORRISBURG TS	8.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.07

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
MURILLO DS	78.00	1.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	78.00	1.13
MUSKOKA TS	36.00	0.32	0.00	0.00	0.00	0.00	0.00	0.00	27.00	0.27	63.00	0.59
NAPANEE TS	7.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.07
NAVAN DS	33.00	0.39	0.00	0.00	0.00	0.00	0.00	0.00	2.00	5.25	35.00	5.64
NEBO TS DESN1	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
NESTOR FALLS DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
NEWINGTON DS	23.00	0.42	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.75	24.00	1.17
NORFOLK TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
NORTHBROOK DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
ORANGEVILLE TS DESN1	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02	4.00	0.04
ORANGEVILLE TS DESN2	114.00	1.44	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	115.00	1.45
ORILLIA TS	55.00	0.51	0.00	0.00	0.00	0.00	0.00	0.00	4.00	3.28	59.00	3.79
ORLEANS TS	27.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.00	0.31
OTONABEE TS DESN1	8.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	11.00	0.10
OTONABEE TS DESN2	60.00	0.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.00	0.88
OWEN SOUND TS	197.00	1.99	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	198.00	1.99
PALMERSTON TS	54.00	2.16	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.13	55.00	2.29
PARRY SOUND TS	39.00	0.29	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	40.00	0.30
PEMBROKE TS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
PETAWAWA DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.05	3.00	3.06
PIC DS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.01
PICTON TS	86.00	0.84	1.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	87.00	0.92
PLEASANT TS DESN1	4.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.95	5.00	0.97
PORT ARTHUR TS #1	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
PORT HOPE TS DESN1	52.00	2.07	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3.00	53.00	5.07

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
PUSLINCH DS	32.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.00	0.30
RAMORE TS	3.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.19
RED LAKE TS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.01
ROCKLAND DS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02
ROCKLAND EAST DS	13.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.19
RUSSELL DS	7.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.06
SAM LAKE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
SAPAWE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
SCHREIBER WINNIPG DS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02
SEAFORTH TS	14.00	0.81	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	15.00	0.82
SHARBOT DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	5.00	0.05
SIDNEY TS	43.00	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.00	0.35
SIOUX NARROWS DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
SMITHS FALLS TS	87.00	1.44	0.00	0.00	0.00	0.00	0.00	0.00	43.00	1.64	130.00	3.08
SOUTH GLOUCESTER DS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
SOUTH MARCH TS	33.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.00	0.31
SOWERBY DS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.01
SPANISH DS	3.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.18
ST ISIDORE TS	28.00	1.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.00	1.84
ST LAWRENCE TS	21.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.00	0.19
ST MARYS TS	8.00	0.43	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.76	9.00	2.19
STAYNER TS	65.00	0.76	0.00	0.00	0.00	0.00	0.00	0.00	3.00	11.16	68.00	11.92
STEWARTVILLE TS	22.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	23.00	0.18
STRATFORD TS	25.00	1.02	0.00	0.00	0.00	0.00	0.00	0.00	3.00	4.51	28.00	5.52
STRATHROY TS	4.00	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.22

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
STRIKER DS	4.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.08
TEMAGAMI DS	0.00	0.00	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
THOROLD TS	5.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.09
TILBURY WEST DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
TILLSONBURG TS	30.00	0.60	0.00	0.00	0.00	0.00	0.00	0.00	25.00	1.06	55.00	1.66
TIMMINS TS	1.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.57	2.00	1.65
TROUT LAKE TS	28.00	0.24	0.00	0.00	0.00	0.00	0.00	0.00	70.00	0.70	98.00	0.94
VERMILION BAY DS	1.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.09
VERNER DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
WALLACE TS	30.00	0.22	0.00	0.00	0.00	0.00	0.00	0.00	40.00	0.40	70.00	0.62
WALLACEBURG TS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
WANSTEAD TS	4.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.07
WARREN DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
WAUBAUSHENE TS	44.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.00	0.34
WENDOVER DS	17.00	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	0.40
WHARNCLIFFE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	2.00	0.02
WHITEFISH DS	13.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08	21.00	0.19
WILHAVEN DS	10.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.00	0.18
WILSON TS DESN2	33.00	16.00	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	34.00	16.01
WINGHAM TS	20.00	0.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.00	0.72
WOLVERTON DS	15.00	0.24	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	18.00	0.27
WONDERLAND TS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
WOODSTOCK TS	23.00	1.20	0.00	0.00	0.00	0.00	0.00	0.00	2.00	1.01	25.00	2.21

Notes on Data

- The BTM DER list consists of both Hydro One owned and non-Hydro One owned DERs.
- Only DERs directly connected to Hydro One's network are included. DERs that are indirectly connected to Hydro One's network (i.e., connected to Local Distribution Companies or transmission or distribution assets owned by other parties) are not included.
- The list only consists of BTM DER Resources that Hydro One has records of. There may be BTM DERs that are utilized by customers for their own purposes (e.g. backup diesel generation in mines). As customers have no obligation to inform Hydro One of these installations, these installations are neither tracked nor included in this list.

Number and MW of Front of the Meter Distributed Energy Resources Connected to Hydro One Feeders by Fuel Type - 2024

The breakdown of front-of-the-meter Distributed Energy Resources (FTM DER) connected to Hydro One Networks Inc.'s (Hydro One) distribution system by station as of December 31, 2024 is as follows:

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
AGIMAK DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
AGUASABON DS	6.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.09
ALLANBURG TS	70.00	1.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.00	1.40
ALLISTON TS	41.00	1.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.00	1.06
ALMONTE TS	112.00	21.82	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	113.00	21.83
ARDOCH DS	13.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.12
ARMITAGE TS DESN1	73.00	7.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.00	7.24
ARMITAGE TS DESN2	93.00	1.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	93.00	1.31
ARNPRIOR TS	119.00	22.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	119.00	22.23
AYLMER TS	50.00	2.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00	2.48
BALLINAFAD MS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
BARWICK TS	103.00	25.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.00	25.99
BATTERSEA DS	70.00	1.24	0.00	0.00	1.00	0.25	0.00	0.00	2.00	1.00	73.00	2.49
BEAMSVILLE TS	7.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.07
BEARDMORE DS #2	0.00	0.00	0.00	0.00	0.00	0.00	1.00	6.00	0.00	0.00	1.00	6.00
BEAVERTON TS	300.00	57.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	300.00	57.72
BELLE RIVER TS	167.00	2.87	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	168.00	12.87
BELLEVILLE TS	205.00	52.76	0.00	0.00	1.00	0.25	0.00	0.00	1.00	0.50	207.00	53.51
BILBERRY CREEK TS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
BLOOMSBURG DS	17.00	13.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	13.24
BRACEBRIDGE TS	15.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.14

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
BRANT TS	107.00	9.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	107.00	9.70
BRANTFORD TS	11.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	1.00	8.10	12.00	8.21
BROCKVILLE TS	219.00	32.53	0.00	0.00	0.00	0.00	0.00	0.00	2.00	10.00	221.00	42.53
BROWN HILL TS	212.00	32.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	212.00	32.97
BUCHANAN TS	14.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.34
BUNTING TS	0.00	0.00	0.00	0.00	0.00	0.00	2.00	4.00	0.00	0.00	2.00	4.00
BURLEIGH DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
CALEDONIA TS	31.00	20.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	20.95
CALSTOCK DS	8.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08
CAMPBELL TS DESN2	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CENTRALIA TS	145.00	5.16	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.50	147.00	5.66
CHESTERVILLE TS	100.00	21.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	21.35
CLARABELLE TS	79.00	2.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	79.00	2.51
CLARENCE DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
CLARKE TS	63.00	1.38	0.00	0.00	1.00	0.30	0.00	0.00	3.00	0.75	67.00	2.43
CLEARWATER BAY DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
COBDEN DS	37.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.00	0.36
COBDEN TS	137.00	4.45	0.00	0.00	1.00	0.50	0.00	0.00	0.00	0.00	138.00	4.95
COCHRANE WEST DS	19.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.00	0.19
COMMERCE WAY TS	94.00	2.90	1.00	18.00	0.00	0.00	0.00	0.00	0.00	0.00	95.00	20.90
CONSTANCE DS	97.00	1.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	97.00	1.44
CRAIG DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
CRILLY DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CROSBY TS	5.00	40.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	40.01
CROSBY TS DESN1	49.00	21.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.00	21.89

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
CROWLAND TS	14.00	0.27	1.00	9.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	9.27
CRYSTAL FALLS TS	43.00	5.62	0.00	0.00	0.00	0.00	3.00	11.50	0.00	0.00	46.00	17.12
CUMBERLAND DS	21.00	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.00	0.39
DEEP RIVER DS	15.00	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.28
DES JOACHIMS DS	3.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.26
DOBBIN DS	24.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24.00	0.34
DOBBIN TS	189.00	14.12	1.00	10.00	0.00	0.00	0.00	0.00	1.00	0.10	191.00	24.22
DOUGLAS POINT TS	117.00	2.10	3.00	11.05	0.00	0.00	0.00	0.00	0.00	0.00	120.00	13.15
DRYDEN TS	31.00	10.28	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.38	33.00	10.66
DUART TS DESN1	103.00	10.91	1.00	10.00	0.00	0.00	0.00	0.00	1.00	0.25	105.00	21.16
DUNDAS TS	210.00	4.89	0.00	0.00	0.00	0.00	0.00	0.00	2.00	8.49	212.00	13.38
DUNNVILLE TS	23.00	0.67	2.00	9.90	0.00	0.00	0.00	0.00	2.00	10.42	27.00	20.99
DYMOND TS	59.00	9.92	0.00	0.00	0.00	0.00	1.00	9.50	0.00	0.00	60.00	19.42
EAR FALLS TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
EDGEWARE TS	107.00	3.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	107.00	3.77
ELLIOT LAKE TS	14.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.20
ELMIRA TS	24.00	0.35	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.25	25.00	0.60
ENFIELD TS DESN 1	92.00	1.56	4.00	35.85	0.00	0.00	0.00	0.00	0.00	0.00	96.00	37.41
ESPANOLA TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
ETON DS	29.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.00	0.33
EVERETT TS	106.00	1.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	106.00	1.10
FALLOWFIELD DS	0.00	0.00	0.00	0.00	1.00	5.55	0.00	0.00	0.00	0.00	1.00	5.55
FAUQUIER DS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06
FERGUS TS	198.00	3.01	3.00	41.20	0.00	0.00	0.00	0.00	1.00	0.14	202.00	44.35
FOREST JURA DS	98.00	1.38	2.00	16.50	0.00	0.00	0.00	0.00	0.00	0.00	100.00	17.88

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
FOREST LEA DS	12.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.12
FRONTENAC TS	130.00	2.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	130.00	2.31
GALT TS	16.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.15
GODERICH TS	79.00	1.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	79.00	1.15
GRAND BEND EAST DS	42.00	1.01	1.00	0.80	2.00	1.00	0.00	0.00	0.00	0.00	45.00	2.81
GREELY DS	67.00	1.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67.00	1.61
HANOVER TS	362.00	8.88	1.00	22.17	0.00	0.00	2.00	0.28	3.00	0.75	368.00	32.08
HARROWSMITH DS	139.00	1.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	139.00	1.28
HAVELOCK TS	242.00	12.11	0.00	0.00	0.00	0.00	1.00	18.00	0.00	0.00	243.00	30.11
HAWTHORNE TS	82.00	11.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	82.00	11.75
HEARST TS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
HERRIDGE LAKE DS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
HIGHBURY TS	35.00	7.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.00	7.49
HINCHINBROOKE DS	39.00	0.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.00	0.58
HOLLAND TS	76.00	2.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	76.00	2.45
INGERSOLL TS	133.00	21.83	0.00	0.00	0.00	0.00	0.00	0.00	4.00	1.00	137.00	22.83
INNISFIL MS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
IROQUOIS FALLS DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
JARVIS TS	33.00	4.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.00	4.21
KAPUSKASING TS	64.00	8.64	0.00	0.00	0.00	0.00	4.00	22.00	0.00	0.00	68.00	30.64
KEITH TS DESN1	6.00	20.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	20.04
KENORA DS	15.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.15
KENT TS DESN1	178.00	2.63	3.00	30.00	0.00	0.00	0.00	0.00	0.00	0.00	181.00	32.63
KENT TS DESN2	125.00	1.25	2.00	20.00	0.00	0.00	0.00	0.00	0.00	0.00	127.00	21.25
KINGSTON GARDINER TS DESN1	147.00	42.35	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	148.00	52.35

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
KINGSTON GARDINER TS DESN2	34.00	0.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.00	0.62
KINGSVILLE TS	191.00	3.00	3.00	25.80	0.00	0.00	0.00	0.00	1.00	12.00	195.00	40.80
KIRKLAND LAKE TS	34.00	8.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.00	8.51
KLEINBURG TS	172.00	3.63	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3.23	173.00	6.86
LAFOREST ROAD DS	1.00	0.01	0.00	0.00	0.00	0.00	1.00	14.00	0.00	0.00	2.00	14.01
LAMBTON TS	42.00	40.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.00	40.61
LARCHWOOD TS	34.00	0.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.00	0.86
LAUZON TS DESN1	3.00	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.23
LAUZON TS DESN2	149.00	2.60	2.00	20.00	1.00	0.25	0.00	0.00	0.00	0.00	152.00	22.85
LDC Owned Station	11.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.11
LEAMINGTON TS DESN 1	163.00	3.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	163.00	3.49
LEAMINGTON TS DESN 2	42.00	0.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.00	0.85
LINDSAY TS	232.00	45.60	0.00	0.00	1.00	0.50	1.00	0.50	1.00	0.34	235.00	46.94
LODGEROOM DS	67.00	1.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67.00	1.10
LONGLAC TS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
LONGUEUIL TS	144.00	51.57	1.00	0.01	3.00	0.46	0.00	0.00	0.00	0.00	148.00	52.04
LONGWOOD TS	158.00	3.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	158.00	3.33
MALDEN TS	109.00	12.39	3.00	29.80	0.00	0.00	0.00	0.00	0.00	0.00	112.00	42.19
MANITOULIN TS	101.00	0.95	2.00	5.60	0.00	0.00	0.00	0.00	0.00	0.00	103.00	6.55
MANITOUWADGE DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
MANITOUWADGE TS	3.00	0.03	0.00	0.00	2.00	13.00	0.00	0.00	0.00	0.00	5.00	13.03
MANOTICK DS	18.00	0.46	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.50	19.00	0.96
MARATHON DS	17.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	0.13
MARGACH DS	11.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.10
MARIONVILLE DS	64.00	0.62	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.75	66.00	1.37

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
MARTINDALE TS	47.00	10.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	47.00	10.91
MASSEY DS	13.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.13
MATTAWA DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
MAZINAW DS	12.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.10
MEAFORD TS	64.00	1.16	1.00	18.00	0.00	0.00	0.00	0.00	0.00	0.00	65.00	19.16
MIDHURST TS DESN1	242.00	37.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	242.00	37.89
MINDEN TS	86.00	2.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86.00	2.28
MONTEITH DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MORRISBURG TS	115.00	20.73	1.00	30.00	0.00	0.00	0.00	0.00	0.00	0.00	116.00	50.73
MOUNTAIN CHUTE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MURILLO DS	100.00	1.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	1.21
MUSKOKA TS	222.00	29.07	0.00	0.00	0.00	0.00	1.00	5.00	0.00	0.00	223.00	34.07
NAKINA DS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.50	1.00	1.50
NAPANEE TS	231.00	60.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	231.00	60.35
NAVAN DS	11.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.10
NEBO TS DESN1	90.00	1.06	0.00	0.00	1.00	3.20	0.00	0.00	0.00	0.00	91.00	4.26
NESTOR FALLS DS	13.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.12
NEWINGTON DS	9.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.10
NIPIGON DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
NORFOLK TS	131.00	11.13	2.00	19.90	0.00	0.00	0.00	0.00	1.00	8.50	134.00	39.53
NORTH BAY TS	1.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.08
NORTH SHORE DS	17.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	0.16
NORTHBROOK DS	31.00	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.52
ORANGEVILLE TS DESN1	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
ORANGEVILLE TS DESN2	361.00	5.44	5.00	44.23	0.00	0.00	0.00	0.00	0.00	0.00	366.00	49.67

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
ORILLIA TS	183.00	31.84	0.00	0.00	0.00	0.00	1.00	1.65	1.00	1.06	185.00	34.55
ORLEANS TS	71.00	3.10	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00	72.00	4.10
OTONABEE TS DESN1	17.00	2.34	0.00	0.00	1.00	1.60	0.00	0.00	0.00	0.00	18.00	3.94
OTONABEE TS DESN2	235.00	9.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	235.00	9.24
OWEN SOUND TS	370.00	10.62	0.00	0.00	1.00	0.10	0.00	0.00	0.00	0.00	371.00	10.72
PALMERSTON TS	256.00	4.76	1.00	0.50	0.00	0.00	0.00	0.00	0.00	0.00	257.00	5.26
PARRY SOUND TS	57.00	3.63	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.00	58.00	5.63
PEMBROKE TS	33.00	0.59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.00	0.59
PETAWAWA DS	12.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.11
PIC DS	11.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.10
PICTON TS	218.00	28.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	218.00	28.78
PLEASANT TS DESN1	23.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.00	0.31
PORT ARTHUR TS #1	30.00	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00	0.28
PORT COLBORNE TS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
PORT HOPE TS DESN1	237.00	34.97	0.00	0.00	1.00	0.01	0.00	0.00	0.00	0.00	238.00	34.98
PUSLINCH DS	96.00	1.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	96.00	1.60
RAMORE TS	12.00	8.11	0.00	0.00	0.00	0.00	1.00	0.52	0.00	0.00	13.00	8.63
RED LAKE TS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
RED ROCK DS	29.00	1.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.00	1.28
ROCKLAND DS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
ROCKLAND EAST DS	14.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.14
RUSSELL DS	7.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.13
SCHREIBER WINNIPG DS	9.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.08
SEAFORTH TS	102.00	2.61	1.00	15.00	0.00	0.00	0.00	0.00	0.00	0.00	103.00	17.61
SHABAQUA DS	9.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.09

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
SHARBOT DS	22.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.00	0.19
SIDNEY TS	246.00	4.04	0.00	0.00	0.00	0.00	1.00	10.00	0.00	0.00	247.00	14.04
SIOUX NARROWS DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
SMITHS FALLS TS	256.00	83.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	256.00	83.34
SOUTH GLOUCESTER DS	13.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.16
SOUTH MARCH TS	66.00	1.28	0.00	0.00	0.00	0.00	0.00	0.00	1.00	6.40	67.00	7.68
SOUTH MIDDLE ROAD TS	9.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	1.00	13.33	10.00	13.42
SOWERBY DS	9.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.08
SPANISH DS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06
ST ISIDORE TS	162.00	23.10	0.00	0.00	2.00	4.70	0.00	0.00	5.00	1.22	169.00	29.03
ST LAWRENCE TS	80.00	81.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	80.00	81.25
ST MARYS TS	51.00	1.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.00	1.19
STAYNER TS	199.00	6.12	2.00	28.45	0.00	0.00	0.00	0.00	0.00	0.00	201.00	34.57
STEWARTVILLE TS	83.00	4.35	0.00	0.00	0.00	0.00	1.00	10.70	0.00	0.00	84.00	15.05
STRATFORD TS	170.00	1.98	0.00	0.00	0.00	0.00	0.00	0.00	3.00	1.10	173.00	3.08
STRATHROY TS	59.00	14.58	1.00	4.10	0.00	0.00	0.00	0.00	0.00	0.00	60.00	18.68
STRIKER DS	60.00	2.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.00	2.54
TEMAGAMI DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
THOROLD TS	30.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00	0.26
TILBURY WEST DS	48.00	0.57	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	49.00	10.57
TILLSONBURG TS	165.00	2.01	2.00	19.80	0.00	0.00	0.00	0.00	0.00	0.00	167.00	21.81
TIMMINS TS	4.00	0.04	0.00	0.00	0.00	0.00	2.00	20.50	0.00	0.00	6.00	20.54
TROUT LAKE TS	87.00	2.35	0.00	0.00	0.00	0.00	2.00	10.80	0.00	0.00	89.00	13.15
VERMILION BAY DS	8.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08
VERNER DS	31.00	0.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.64

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
WALLACE TS	100.00	0.97	0.00	0.00	0.00	0.00	1.00	0.60	0.00	0.00	101.00	1.57
WALLACEBURG TS	175.00	1.72	1.00	10.00	0.00	0.00	0.00	0.00	1.00	5.16	177.00	16.88
WANSTEAD TS	185.00	3.48	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	186.00	13.48
WARREN DS	16.00	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.71
WAUBAUSHENE TS	143.00	43.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	143.00	43.69
WENDOVER DS	62.00	13.11	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.50	63.00	13.61
WHARNCLIFFE DS	18.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.00	0.18
WHITEFISH DS	16.00	0.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.62
WILHAVEN DS	21.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.00	0.19
WILSON TS DESN2	142.00	21.96	0.00	0.00	0.00	0.00	1.00	0.01	1.00	19.40	144.00	41.37
WINGHAM TS	130.00	1.98	1.00	18.00	0.00	0.00	0.00	0.00	0.00	0.00	131.00	19.98
WOLVERTON DS	61.00	1.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.00	1.35
WONDERLAND TS	39.00	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.00	0.61
WOODSTOCK TS	36.00	2.90	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	37.00	2.91

Notes on Data

- The FTM DER list consists of both Hydro One owned and non-Hydro One owned DERs.
- Only resources directly connected to Hydro One’s network are included. Resources that are indirectly connected to Hydro One’s network (i.e., connected to Local Distribution Companies or transmission or distribution assets owned by other parties) are not included.

Section 3.2

Residential Energy Storage Performance Data

Residential Behind the Meter Battery Energy Storage System – Performance Data for 2024

The breakdown of residential behind-the-meter Battery Energy Storage System (BTM BESS) performance data for units connected to Hydro One Networks Inc.'s (Hydro One) distribution system for the period, January to December, 2024, is provided below.

BTM BESS Performance Reporting - 2024					
Station Name	**Count**	**Capacity (MW)**	**Total Customer Outage Time [customer x hr]**	**Total Outage Duration Avoided by BESS [customer x hr]**	**% Outage hrs Mitigated**
Arnprior TS	2	0.02	7.08	7.1	100%
Aylmer TS	1	0.01	0.45	0.5	100%
Brant TS	2	0.02	23.07	23.1	100%
Buchanan TS	2	0.02	86.28	85.2	99%
Centralia TS	4	0.04	19.65	16.4	83%
Cobden TS	12	0.12	516.15	516.1	100%
Constance DS	1	0.01	32.00	31.8	99%
Crosby TS	3	0.03	38.13	38.1	100%
Des Joachims DS	1	0.01	0.00	0.0	100%
Dunnville TS	2	0.02	34.65	34.7	100%
Goderich TS	1	0.01	36.65	36.7	100%
Havelock TS	6	0.06	46.75	46.0	98%
Herridge Lake DS	3	0.03	70.22	70.2	100%
Hinchinbrooke DS	4	0.04	9.57	9.6	100%
Ingersoll TS	14	0.14	1702.22	1702.1	100%
Kleinburg TS	1	0.01	0.82	0.8	100%
Larchwood TS	4	0.04	30.73	30.1	98%
Lindsay TS	4	0.04	367.73	367.7	100%
Martindale TS	6	0.06	36.98	37.0	100%
Mattawa DS	1	0.01	0.17	0.2	100%
Minden TS	24	0.24	544.33	544.0	100%

BTM BESS Performance Reporting - 2024					
Station Name	**Count**	**Capacity (MW)**	**Total Customer Outage Time [customer x hr]**	**Total Outage Duration Avoided by BESS [customer x hr]**	**% Outage hrs Mitigated**
Muskoka TS	23	0.23	952.00	915.8	96%
Muskoka TS	1	0.01	0.30	0.3	100%
Orangeville TS	2	0.02	6.87	6.9	100%
Otonabee TS	3	0.03	19.70	19.7	100%
Parry Sound TS	1	0.01	37.92	37.9	100%
Seaforth TS	1	0.01	2.45	2.5	100%
SHARBOT DS	3	0.03	49.02	49.0	100%
Smiths Falls TS	39	0.39	1751.33	1739.3	99%
Stewartville TS	1	0.01	0.05	0.1	100%
Tillsonburg TS	23	0.23	549.37	548.3	100%
Trout Lake TS	70	0.7	1757.13	1756.3	100%
Wallace TS	40	0.4	914.00	906.1	99%
Wharncliffe DS	1	0.01	11.97	12.0	100%
Whitefish DS	7	0.07	275.57	251.4	91%
Wolverton DS	3	0.03	22.60	22.6	100%

Reference Table	
Name	**Description**
Station Name	Network connection downstream of the first level connection to Hydro One Transmission circuit
Count	Number of BESS Units connected to Station
Capacity	Total MW Capacity of BESS Units at Station
Total Customer Outage Time	Total annual customer x hours of outage time experienced by BESS units at a Station
Total Outage Duration Avoided by BESS	Total annual grid outage time (customer x hours) serviced by BESS to minimize customer outage time
% Outage hrs Mitigated	Total customer x hours of outage backed up by BESS divided by Total Customer Outage Time

Section 3.3

Grid Scale Energy Storage Performance Data

Grid Scale Front of the Meter Battery Energy Storage System – Performance Data for 2024

The breakdown of Hydro One Networks Inc. (Hydro One) owned grid scale front-of-the-meter Battery Energy Storage Systems (FTM BESS) connected to Hydro One's distribution system as of December 31, 2024 is as follows:

Hydro One FTM BESS Performance Data - 2024						
Station Name	**Year**	**# of Grid Outage Events**	**Total Grid Outage (Hours) = (A)**	**BESS Operation (Hours) = (B)**	**% Outage Hrs Mitigated = (B) / (A)**	**Availability %**
Nakina DS (Aroland BESS)	2024	12	64.7	43.6	67%	98%

REFERENCE TABLE	
Name	**Description**
Station Name	Hydro One Station to which FTM BESS is connected
# of Grid Outage Events	Number of annual grid outages experienced by the BESS
Grid Outage	Total annual grid outage time (hours) experienced by BESS
BESS Operation	Total annual grid outage time (hours) serviced by BESS to minimize customer outage time
% Outage Hrs Mitigated	BESS Operation Time divided by Grid Outage Time
Availability %	% of Hours BESS was available to provide support to a grid outage divided by Total In-Service Minutes for Year