Ontario Energy Board | Commission de l'énergie de l'Ontario

# Ontario Energy Board

## Filing Requirements For Electricity Distribution Rate Applications - 2026~~5~~ Edition for 2027~~6~~ Rate Applications

# Chapter 5

## Distribution System Plan

**December 16~~9~~, 2025~~4~~**

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# Chapter 5 Filing requirements for distribution system plans for electricity distribution cost of service rate applications

## 5.0 Introduction

These Chapter 5 filing requirements set out the relevant information required by the Ontario Energy Board (OEB) in accordance with the renewed regulatory framework (RRF) for electricity[1] and the Handbook for Utility Rate Applications (Handbook) to assess distributor applications involving planned expenditures on distribution systems and general plant. A Distribution System Plan (DSP) consolidates the documentation related to a distributor's asset management process and capital expenditure plan, as described in the Handbook.[2]

The OEB's expectation is that distributors maintain good asset management at all times, not just for the purpose of filing a DSP for a rate application. Good distributor planning is an essential prerequisite to the performance-based rate-setting approaches established under the Handbook, and necessary to ensure that the four performance outcomes the OEB has established for electricity distributors, namely Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance[3], are being achieved.

### 5.0.1 Application and Scope

These filing requirements apply to licensed, rate regulated electricity distributors~~ion utilities~~ in Ontario when filing DSPs in accordance with the frequency set out by the OEB in section 5.1.3 of these requirements.

### 5.0.2 The OEB's Evaluation of DSPs

DSP filings must address whether a distributor has achieved and will continue to achieve the four performance outcomes the OEB has established for electricity distributors. Section 5.4.2 explains the specific criteria the OEB will use to evaluate

[1] The renewed regulatory framework for electricity is a comprehensive, performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. See *Report of the OEB – A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*. (the *RRF Report*); p. 2.
[2] Handbook for Utility Rate Applications, p.13
[3] Ibid, pp. 2-3

whether a DSP, and in particular, how the material[4] projects and~~/~~ programs proposed for cost recovery in a DSP, address these four outcomes.[5]

## 5.1 General & Administrative Matters

These filing requirements provide a standardized approach to a distributor's filings of asset management and capital expenditure plan information in support of a rate application. Distributors are expected to include and clearly identify in their filings the information set out in these filing requirements, and to use the terminology and formats set out in these filing requirements.

### 5.1.1 Purpose of Filing a Distribution System Plan

To implement the policy objectives of the RRF as set out in the Handbook, all filing requirements related to DSPs have been consolidated in Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications.

Filing a DSP with an application to the OEB will provide information to the OEB and interested stakeholders including, but not necessarily limited to, a distributor's approach to evaluating its performance, management of its assets, and capital investment plans~~.~~ and is key to the OEB's determination of the capital component to be recovered in just and reasonable rates.

### 5.1.2 Investment Categories

A distributor's investment projects and programs must be grouped for filing purposes into one of the four investment categories listed below.

**Table 1 – Investment Categories & Example Drivers and Projects/Programs**

| | Example Drivers | Example Projects / Programs |
|---|---|---|
| **system access** | Customer service requests | – New customer connections<br>– Modifications to existing customer connections<br>– Expansions for customer connections or property development |
| | Other 3rd party infrastructure development requirements | – System modifications for property or infrastructure development (e.g., relocating pole lines for road widening) |

[4] An investment is "material" if the materiality threshold set out in Chapter 2 of the *Filing Requirements for Electricity Transmission and Distribution Applications* is met.
[5] Handbook for Utility Rate Applications, pp. 9-22

| | Example Drivers | Example Projects / Programs |
|---|---|---|
| | Mandated service obligations (Distribution System Code (DSC); Conditions~~.~~ of Service~~.~~; etc.) | – Metering<br>– Long term load transfer |
| **system renewal** | Assets/asset systems at end of service life due to:<br>– Failure<br>– Failure risk (asset condition assessment)<br>– Substandard performance<br>– High performance risk<br>– Functional obsolescence | – Programs to refurbish/replace assets or asset systems, e.g.: batteries; cable (by type); cable splices; civil works; conductor; elbows & inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type) |
| **system service** | Expected changes in load that will constrain the ability of the system to provide consistent service delivery | – Property acquisition<br>– Capacity upgrade (by type); e.g., phases; circuits; conductor; voltage; transformation; regulation<br>– Line extensions<br>– Non-wires solutions (NWSs) that reduce peak demand[6] |
| | System operational objectives:<br>– Safety<br>– Reliability<br>– Power quality<br>– System efficiency<br>– System Hardening<br>– Other performance/functionality | – Protection & control upgrade; e.g., reclosers; tap changer controls/relays; transfer trip<br>– Automation (new/upgrades) by device type/function<br>– Supervisory control and data acquisition (SCADA)<br>– Distribution loss reduction<br>– New technologies/capabilities<br>– System hardening projects aimed at improving distribution system resiliency to extreme weather |
| **general plant[7]~~1~~** | – System capital investment support<br>– System maintenance support<br>– Business operations efficiency<br>– Non-system physical plant | – Land acquisition<br>– Structures & depreciable improvements<br>– Equipment and tools<br>– Supplies<br>– Finance/admin/billing software & systems<br>– Rolling stock<br>– Intangibles (e.g., land rights; capital contributions to other utilities) |

~~Note: 1. Includes only 1900 series accounts.~~

[6] NWSs may also be appropriate for other investment categories.
[7] Includes only 1900 series accounts.

- ***System access*** investments are modifications (including asset relocation) to a distributor's distribution system that a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system.
- ***System renewal*** investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.
- ***System service*** investments encompass modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements.
- ***General plant*** investments encompass modifications, replacements or additions to a distributor's assets that are not part of its distribution system including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day to day business and operations activities.

A project or program involving two or more drivers associated with different categories should be placed in the category corresponding to the trigger driver. For example, a project triggered by the need to replace end of service life components in a distribution station should be considered a system renewal investment, even if in anticipation of future system requirements (a system service driver) the project includes assets rated for a higher voltage and/or capable of handling reverse flows. Note, however (as detailed in section 5.4.2), information on all drivers of a given project or program must be used to justify the need for, and quantum of proposed capital investments.

### 5.1.3 Timing of Filing

All distributors are required to file a DSP when filing a cost of service application under a Price Cap Incentive Rate-setting (IR) or a Custom IR application (collectively referred to as rebasing applications). Distributors proposing to use the Annual IR Index method are not required to file a DSP when filing an application.[8] The OEB may also require a DSP to be filed in relation to an Incremental Capital Module, a Z-factor application, or following a merger / acquisition / amalgamation / divestiture application.[9]

[8] Distributors applying for funding for NWSs outside of rebasing are required to include a targeted update to their DSP, to demonstrate the need for the NWS and identify the system need being addressed.
[9] EB-2017-0269, EB-2018-0236, Decision and Order, December 20, 2018, p17

### 5.1.4 Very Small ~~Utilities~~ Distributor ~~(VSU)~~ DSP Sample

The OEB ~~has~~ initially posted a DSP Sample on March 28, 2024, suitable for a cost of service application for very small ~~utilities~~ distributors~~(VSUs)~~ (less than 5,000 customers). In addition to the DSP Sample, the OEB posted a DSP Requirement & ~~VSU~~ Information Requirement document to guide ~~VSUs~~ very small distributors in preparing their DSP.

The initial DSP Sample considered the Filing Requirements for 2025 Rate Applications. Distributors who wish to use the DSP Sample must consider updates to the filing requirements for both 2026 and 2027 rate applications, such as but not limited to:

- Section 5.2.3.3 – Distributor-Specific Reliability Targets
- Section 5.3.1.1 – Process (specifically the Integrated Energy Plan)
- Section 5.3.4 – System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources
- Section 5.3.6 – Climate Vulnerability Assessment and System Hardening (VASH)
- Section 5.4.2.2 – Benefit-Cost Analysis Framework (BCA Framework)

The latest version of the DSP Sample and the DSP Requirement & Information Requirement document can be found on the OEB's 2027 Electricity Distribution Rate applications webpage (2027 EDR webpage).

## 5.2 Distribution System Plans

Distributors are encouraged to organize the required information using the section and subsection headings indicated from here onwards. If a distributor's application uses alternative section headings and/or arranges the information in a different order, the distributor shall provide a table that clearly cross-references the headings/subheadings used in the application to the section headings/subheadings indicated in these filing requirements. Distributors are also encouraged to structure the application so that all DSP appendices and supporting materials are included after the main DSP body text, to facilitate review.

The DSP's duration is a minimum of ten years in total, comprising of a~~n~~ historical period and a forecast period. The historical period is the first five years of the DSP duration, consisting of five historical years, ending with the bridge year. For distributors that have not filed a DSP within the past five years, the historical period is from the test year of the distributor's last cost of service application to the bridge year. The forecast period is the last five years of the DSP duration, consisting of five forecast years, beginning with the test year of the current cost of service application.

### 5.2.1 Distribution System Plan Overview

The distributor must provide a high-level overview of the information filed in the DSP and is encouraged not to unnecessarily repeat details contained in the rest of the DSP. The overview should include capital investment highlights and changes since the last DSP. A distributor should list the objectives it plans to achieve through this DSP, which will be used as a baseline comparison in the performance measurement section below. This DSP will be used to inform and potentially support any requests for incremental capital module (ICM) funding during the 5-year DSP forecast period.[10]

### 5.2.2 Coordinated Planning with Third Parties

A distributor must demonstrate that it has coordinated infrastructure planning with customers (e.g., large customers, subdivision developers, and municipalities), the transmitter (e.g., Regional Infrastructure Planning), other distributors, the Independent Electricity System Operator (IESO) (e.g., Integrated Regional Resource Planning) or other third parties where appropriate. A distributor should explain whether the consultation~~(s)~~ affected the distributor's DSP as filed and, if so, provide a brief explanation as to how. For consultations that affect the DSP, a distributor should provide an overview of the consultations and relevant material supporting the effects the consultations had on the DSP.

An overview of any consultation~~(s)~~ should include:

- The purpose and outcome of the consultation;
- whether the distributor initiated the consultation or was invited to participate in it and the other participants in the consultation process (e.g., customers, transmitter, IESO).

A distributor should file the most recent ~~r~~Regional P~~p~~lan (i.e., Integrated Regional Resource Plan, Regional Infrastructure Plan). In the absence of a regional plan, the distributor should file a Regional Planning Status Letter from the transmitter. Further, a distributor is required to identify any inconsistencies between its DSP and any current Regional Plan. If there are any inconsistencies, the distributor shall explain the reasons why, particularly where a proposed investment in their DSP is different from the recommended optimal investment identified in the Regional Plan.

[10] If a distributor is aware of a potential future ICM request but has chosen not to apply for the Advanced Capital Module (e.g. due to uncertainty of whether the project will proceed or a lack of complete information to fully support the request in the DSP), the distributor should still identify the project and provide commentary around the potential future ICM request.

#### 5.2.2.1 Telecommunications Entities

On January 11, 2022, the OEB issued further guidance[11] to the regulation that requires distributors to consult with any telecommunications entity that operates within its service area when preparing a capital plan for submission to the OEB, for the purpose of facilitating the provision of telecommunications services, and include the following information in its capital plan

- The number of consultations that were conducted and a summary of the manner in which the distributor determined with whom to consult.
- A summary of the results of the consultations.
- A statement as to whether the results of the consultations are reflected in the capital plan and, if so, a summary as to how.

#### 5.2.2.2 Renewable Energy Generation (REG)

A distributor is expected to coordinate with the IESO in relation to REG investments and confirm if there are REG investments in the region.

If there are REG investments proposed in the DSP, a distributor is expected to demonstrate that it has coordinated with the IESO, other distributors, and/or transmitters, as applicable, and that the investments proposed are consistent with a Regional Infrastructure Plan. This coordination is demonstrated by a comment letter provided by the IESO, to be filed with the DSP.

### 5.2.3 Performance Measurement for Continuous Improvement

#### 5.2.3.1 Distribution System Plan

Distributors are expected to summarize objectives for continuous improvement (e.g., reliability improvement and other desired outcomes) the distributor set out to address in its last DSP, and to discuss whether these objectives have been achieved. For objectives not achieved, a distributor should explain how it affects the current DSP and, if applicable, improvements a distributor has implemented to achieve the objectives set out in s~~S~~ection 5.2.1.

[11] OEB Letter – Capital Planning to Support Telecommunications Projects, January 11, 2022

#### 5.2.3.2 Service Quality and Reliability

Chapter 7 of the OEB's DSC~~*Distribution System Code*~~ outlines the OEB's expectations regarding Service Quality Requirements (SQR) for Electricity Distributors. A distributor is required to provide the reported SQRs for the last five historical years. A distributor should also provide explanations for material changes in service quality and reliability, and whether and how the DSP addresses these issues. The OEB expects any five-year declining trends in reliability for SAIDI and SAIFI to be explained. If a distributor has reliability targets established in a previously filed DSP, as described below, any under-performance should also be explained.

A completed Appendix 2-G, documenting both the Service Quality and Service Reliability indicators, must be filed. A distributor must confirm that data is consistent with the scorecard or must explain any inconsistencies.

A summary of performance for the historical period using the methods and measures (metrics/targets) identified and described above, and how this performance has trended over the period, ~~should~~ must be included. This summary must include historical period data on[12]:

- All interruptions
- All interruptions excluding loss of supply
- All interruptions excluding Major Events and loss of supply for the following:
  - The distribution system average interruption frequency index (SAIFI)
  - System average interruption duration index (SAIDI)[13]

The applicant ~~should~~ shall also provide a summary of Major Events that occurred since the last cost of service filing.

For each cause of interruption, a distributor ~~should~~shall, for the last five historical years, report the following data:

- Number of interruptions that occurred as a result of the cause of interruption
- Number of customer interruptions that occurred as a result of the cause of interruption

[12] Note: The information in this section were originally from Chapter 2.2.2.8.
[13] The data should be calculated as stipulated in section 2.1.4.2 of the OEB's Reporting and Record Keeping Requirements.

- Number of customer-hours of interruptions that occurred as a result of the cause of interruption

#### 5.2.3.3 Distributor-~~-~~Specific Reliability Targets

As established in the OEB letter of January 28, 2025~~*Report of the OEB: Electricity Distribution System Reliability Measures and Expectations*~~[14], a distributor's reliability performance targets are calculated based on three components: (1) a baseline for each of SAIDI and SAIFI metric, which is based on the distributor's five-year average performance for each metric; (2) an adjustment factor based on the distributor's performance trend; and (3) an adjustment factor reflecting benchmarking results~~distributors' SAIDI and SAIFI performance is expected to meet the performance target set out in the Scorecard~~.[15]

Distributors who wish to establish alternative performance targets~~,performance expectations based on something other than historical performance~~ should provide evidence of their capital and operational plan and other factors that justify the reliability performance they plan to deliver. A distributor proposing an alternative target is not required to address the default target beyond providing justification for using the alternative. The distributor should also provide a summary of any feedback from their customers regarding the reliability of the distributor's system.

Regardless of methodology used, distributors should use their reliability performance targets as an input to investment projects and programs contained in their DSPs. The OEB will evaluate how distributors are taking these targets into consideration in their planning processes.

~~Distributors who wish to use SAIDI and SAIFI performance benchmarks that are different than the historical average must provide evidence to support the reasonableness of such benchmarks.~~

## 5.3 Asset Management Process

A distributor must use an asset management process to plan, prioritize, and optimize expenditures. The purpose of the information requirements set out in this section is to provide the OEB and stakeholders with an understanding of the distributor's asset

[14] EB-~~2014-0189~~2021-0307, letter issued ~~August~~ January ~~25~~28, ~~2015~~2025.
[15] Reliability Performance Targets (Reliability and Power Quality Review - OEB File No. EB-2021-0307), letter issued October 3, 2025.

management process, and the links between the process and the expenditure decisions that comprise the distributor's capital investment plan.

### 5.3.1 Planning Process

The distributor must provide an overview of its planning process[16] that has informed the preparation of the distributor's five-year capital expenditure plan (a flowchart accompanied by explanatory text may be helpful).

A distributor should provide a summary of any important changes to the distributor's asset management process (e.g., enhanced asset data quality or scope, improved analytic tools, process refinements, etc.) since the last DSP filing.

#### 5.3.1.1 Process

A distributor should provide the processes used to identify, select, prioritize (including reprioritizing investments over the five-year term), optimize and pace the execution of investments over the term of the DSP. A distributor should be able to demonstrate that it has considered the correlation between its capital plan and customers' feedback and needs. A distributor should also demonstrate that it has considered the potential risks of proceeding/not proceeding with individual capital expenditures (e.g., the risk/benefit of a reactive service transformer replacement program instead of proactively replacing service transformers).

A distributor should demonstrate how it undertakes grid optimization using an approach that considers the distributor's whole system. This should include, where applicable, assessing the use of distribution rate-funded NWSs, as well as cost-effective implementation of distribution improvements affecting reliability and meeting customer needs at acceptable costs to customers, and other innovative technologies.

A distributor must also demonstrate that it has a planning process for future capacity needs of its distribution system, which must include, among other aspects, increased adoption of electric vehicles.

On November 2, 2022, the OEB posted the "Load Forecast Guideline for Ontario" provided by the Regional Planning Process Advisory Group (RPPAG), which provided guidance in the development of demand forecasts to increase consistency among distributors.[17] Distributors should consider this guidance when developing their load

[16] This includes a distributor's capital expenditure planning process.~~, which was previously under Section 5.4 of the Distribution System Plan~~

[17] Load Forecast Guideline for Ontario – Guidance for the Development of Regional Planning Demand Forecasts, October 13, 2022.

forecasts. The guidance recommended a sensitivity analysis to capture uncertainty in the demand forecast and noted “one of the evolving components with respect to the demand for electricity is electrification which is expected to change the growth patterns such as they are not well represented by historical trends.”[18]

On June 12, 2025, the OEB received a directive regarding the implementation of the Government of Ontario’s Integrated Energy Plan (IEP).[19] Pursuant to that directive, and specifically in relation to item 2 (2.1 and 2.2):

- A distributor should describe how its planning processes have been impacted by its multiple demand load forecasts, as described in Exhibit 3 of the Chapter 2 Filing Requirements for Electricity Distribution Cost of Service Rate Applications. This should include qualitative and quantitative risk and uncertainty assessments, as appropriate, for each demand load forecast.
- A distributor should incorporate cost projections for future investments that reflect reasonable assumptions for cost trends.
- A distributor should consider frequent and extreme weather impacts on energy infrastructure resilience and ensure future average, minimum and maximum temperatures are considered (this can be considered in the load forecast described in Chapter 2 Filing Requirements Section 2.3.1.3).
- Where a system investment, policy, or program is intended to facilitate fuel switching, the distributor should consider costs and benefits across impacted energy systems.

Distributors should begin incorporating these requirements into their applications on a best-efforts basis by June 30, 2026. Distributors must address the requirements in applications filed after April 1, 2027 (expected for rates effective January 1, 2028 or later).

#### 5.3.1.2 Data

A distributor should identify, describe, and provide a summary of the data used in the processes above to identify, select, prioritize, optimize and pace the execution of investments over the term of the DSP (e.g., asset condition by major asset type and reliability information).

[18] Load Forecast Guideline for Ontario, p. 17.

[19] Directive regarding the implementation of the Government of Ontario’s Integrated Energy Plan - Energy for Generations: Ontario’s Integrated Plan to Power the Strongest Economy in the G7, June 12, 2025, p.5

### 5.3.2 Overview of Assets Managed

The a~~A~~ssessment of a DSP~~s~~ requires a comprehensive understanding of all aspects of the assets managed by a distributor. Distributors may vary in terms of the level of detail that they choose to record for their distribution assets, but the expectation is that in assessing the condition of major assets (e.g., station transformers and poles), solely using asset age is not sufficient.

A distributor should provide an overview of its distribution service area (e.g., system configuration; urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for supporting its capital expenditures over the forecast period. A distributor should provide asset information (e.g., asset capacity and utilization; asset condition; asset failures/performance; asset risks; and asset demographics), by major asset type, that may help explain the specific need for the capital expenditures and demonstrate that a distributor has considered all economic alternatives. There should also be a statement as to whether the distributor has had any transmission or high voltage assets (> 50kV) deemed previously by the OEB as distribution assets, and whether there are any such assets that the distributor is asking the OEB to deem as distribution assets in the present application.

A distributor should also provide a description of whether the distributor is a host distributor (i.e., distributing electricity to another distributor’s network at distribution-level voltages) and/or an embedded distributor (i.e., receiving electricity at distribution-level voltages from any host distributor(s)). The distributor must identify any embedded and/or host distributor(s). Partially embedded status (i.e., where part of the distributor’s network is served by one or more host distributors but where the distributor is also connected to the high voltage transmission network) must be clearly identified, including the percentage of load that is supplied through the host distributor(s). If the distributor is a host distributor, the distributor should identify whether there is a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes (such as GS > 50 kW).

### 5.3.3 Asset Lifecycle Optimization Policies and Practices

An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. The Information provided should be sufficient to show the trade-off between spending on new capital (i.e., replacement) and life-extending refurbishment. A distributor should also be able to demonstrate that it has carried out cost-effective system operations and maintenance (O&M) activities to sustain an asset to the end of its service life (and can include references to the ~~Distribution System Code~~DSC).

A distributor should explain the processes and tools it uses to forecast, prioritize, and optimize system renewal spending and how a distributor intends to operate within budget envelopes. For prioritizing capital expenditures, a distributor should help the audience understand the approaches the distributor uses to balance a customer's need for reliability and capital expenditure costs. A distributor should also demonstrate that it has considered the potential risks of proceeding/not proceeding with individual capital expenditures.

A distributor should also be able to demonstrate that in planning the lifecycle of an asset, it has considered the future capacity requirements of the asset such that it does not need to be replaced prematurely due to capacity constraints.

A distributor should provide a summary of any important changes to the distributor's asset life optimization policies, processes, and tools since the last DSP filing.

### 5.3.4 System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources

A distributor ~~should~~ shall provide a list of restricted feeders by name, the feeder designation, the reason for the restriction, and number of connected customers, and explain if there are plans to improve ~~their~~ its distribution system's ability to connect distributed energy resources.

If a distributor has incurred or expects to incur costs to accommodate and connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the *Ontario Energy Board Act, 1998*, then a distributor should refer to Appendix A of these filing requirements.

Pursuant to item 15 of the IEP Directive, and to continue the efforts to update distributed energy resources connections processes, where a distributor plans to improve the distribution system's ability to connect additional distributed energy resources in areas with restricted hosting capacity, the distributor must include in its application an assessment of potential solutions, including both infrastructure-based and non-infrastructure-based options.

### 5.3.5 Non-Wires Solutions to Address System Needs

The Non-Wires Solutions Guidelines for Electricity Distributors (the NWS Guidelines)[20] provide OEB guidance on the role of NWSs for rate-regulated electricity distributors and the treatment of NWSs in distribution rate applications. The NWS Guidelines require distributors to incorporate consideration of NWSs into their distribution system planning process by considering whether a distribution rate-funded NWS may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure. NWSs potentially eligible for distribution rate funding are not limited to energy efficiency programs and include activities that reduce instantaneous electricity demand, including demand response and energy storage.[21]

A distributor's DSP should describe how it has taken NWSs into consideration in its planning process. The degree of consideration of NWSs in meeting system needs should be proportional to the expected benefits, and will likely vary across distributors, taking into account the size and resources of a distributor. NWSs will not be a viable alternative for all types of traditional infrastructure investments. Distributors are encouraged to take account of learnings from NWSs that have been undertaken by other electricity distributors, in Ontario or elsewhere.

Distributors are required to document their consideration of NWSs when making investment decisions on electricity system needs with an expected capital cost of $2 million or more, excluding general plant investments, making use of the ~~Benefit-Cost Analysis Framework (~~BCA Framework~~)~~. The requirements of the BCA Framework are detailed in s~~S~~ection 5.4.2.2.

Distributors may apply to the OEB for funding through distribution rates for NWSs as specified in the NWS Guidelines. Distributors must explain the proposed activity in the context of the distributor's DSP, including providing details on the system need that is being addressed, any infrastructure investments that are being avoided or deferred as a result of the NWS (this could include investments upstream of a distributor), and the prioritization of the proposed NWS relative to other system investments in the DSP. A

[20] EB-2024-0118, March 28, 2024
[21] More examples are provided in the NWS Guidelines s~~S~~ection 2

distributor should provide evidence as to why the proposed NWS is the preferred approach (alone or in combination with an infrastructure solution) to meeting a system need, including an assessment of the projected benefits to customers relative to cost impacts, following the requirements of the BCA Framework. Any proposal for a rate funded, distributor-owned NWS must demonstrate that a distributor has meaningfully explored contracting services from non-utility owned distributed energy resources – including providing sufficient lead time for third-party solutions to be identified and implemented – and doing so is either not feasible or less cost-effective.

### 5.3.6 Climate Vulnerability Assessment and System Hardening

The VASH policy is intended to complement distributors' existing planning processes.[22] Integrating resilience considerations into established processes will allow distributors to align resilience efforts with existing planning drivers such as asset renewal. This approach will help identify new options for dealing with end-of-life infrastructure while simultaneously creating additional value for customers by enhancing system resiliency.

The following requirements pertaining to VASH policy will apply on a best-efforts basis for applications filed for 2027 rates and will become mandatory for applications for 2028 rates.

A distributor is expected to perform Vulnerability Assessment (VA) using either the Generic Option or the Custom Option, as defined in the VASH policy. The assessment should identify parts of the distribution system (i.e., locations and asset classes) that are most vulnerable to extreme weather and other climate-related events. A distributor selecting the Generic Option is expected to upload, alongside the discussion of vulnerability assessment results in its DSP, a completed version of the Vulnerability Assessment Toolkit (VA Toolkit) that is available within the VASH Toolkit developed by the OEB.[23] A distributor using the Custom Option should ensure that the vulnerability assessment methodology it uses meets the criteria outlined in the VASH policy. It is also expected to file its custom vulnerability assessment study including the detailed calculations along with the discussion of results in its DSP. The assessment should be supported by clearly documented input data sources, rationale for asset and climate peril selection, and justification for any deviations from standard approaches.

After completing the VA, a distributor should conduct a pre-assessment to determine whether technically and economically feasible system hardening investments exist.

[22] EB-2024-0199: VASH Report, October 7, 2025
[23] EB-2024-0199: VA Toolkit, October 7, 2025

For example, as a part of the pre-assessment, distributors may:

- **Prioritize its analysis on the most significant vulnerabilities**- identified in the VA—those with the highest probability of failure or greatest potential impact on customers—while applying professional judgment and operational experience to focus effort where it is most likely to yield actionable solutions. Distributors must document their prioritization method and how the distributor has chosen to define significant vulnerabilities (e.g., top 10% of vulnerable locations or top 10 projects). This ensures the analysis is targeted and manageable, while still allowing flexibility to examine additional areas where warranted.
- **Leverage historical data and operational experience**- to identify areas of the system that have experienced repeated or severe impacts from extreme weather events.
- **Assess the results of the VA in conjunction with other relevant information**, such as asset condition assessments, historical performance, and alignment with other capital plans (e.g., system renewal or grid modernization). Distributors should consider resilience as a complementary planning driver – factoring in potential resilience benefits when evaluating investment options triggered by non-resilience drivers. This ensures resilience is proactively embedded in broader planning decisions.
- **Consider geographic and environmental factors**, such as vegetation density, terrain, or location that may influence the feasibility or urgency of hardening measures.
- **Evaluate the technical feasibility of system hardening solutions** to address the identified vulnerabilities, guided by a detailed understanding of the distribution system.
- **Document the rationale for project selection or exclusion**, including why certain vulnerabilities may not be addressed (e.g., no viable solution, cost-prohibitive).

Regardless of whether the pre-assessment identifies economically plausible projects, a distributor is expected to- document and explain its pre-assessment approach and -submit it as part of its DSP. If a pre-assessment does not identify any economically plausible investments, the distributor does not need to conduct a benefit-cost analysis.

If the pre-assessment identifies economically plausible system hardening investments, a distributor must conduct a benefit-cost analysis for VASH for those investments and include the completed benefit-cost analysis for those projects in its application along with the pre-assessment results. Benefit-cost analyses are to be prepared for each specific system need and not applied generically across the entire system. However, a single benefit-cost analysis may be used to support a program intended to address multiple, similar needs that may exist at different locations within the distribution system.

A distributor using the Generic Option is expected to use the Benefit-Cost Analysis Toolkit available within the VASH Toolkit to demonstrate that the proposed system hardening investments are beneficial and they provide value to its customers. A distributor choosing to pursue the Custom Option should ensure that the benefit-cost analysis methodology it uses meets the criteria outlined in the VASH policy.

## 5.4 Capital Expenditure Plan

The capital expenditure plan should set out and comprehensively justify a distributor's proposed expenditures on its distribution system and general plant over a five-year planning period, including investment and asset-related O&M expenditures.

A distributor's DSP details the system investment decisions developed on the basis of information derived from its planning process. It is critical that investments be justified in whole or in part by reference to specific aspects of that process. As noted in section 5.2 above, a DSP must include information on the historical and forecast period.

### 5.4.1 Capital Expenditure Summary

The purpose of the information filed under this section is to provide a snapshot of a distributor's capital expenditures over the DSP's duration (including both a historical and forecast period) as outlined in section 5.2. ~~a 10-year period, including five historical years and five forecast years.~~ Despite the multi-purpose character, a project or program may have, for summary purposes the entire cost of individual projects or programs are to be allocated to one of the four investment categories on the basis of the primary (i.e., initial or trigger) driver of the investment. For material projects/programs, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or program for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC.

The distributor must provide completed appendices 2-AA – Capital Projects Table and 2-AB – Capital Expenditure Summary Table along with the following information about a distributor's capital expenditures:

- An analysis of a distributor's capital expenditure performance for the DSP's historical period. This should include an explanation of variances by investment or category, including that of actuals versus the OEB-approved/planned amounts from~~for~~ the applicant's last OEB-approved cost of service or custom IR application and DSP (the variance analysis should also include variances in planned and actual volume of work completed). A distributor should particularly explain variances in a given year that are much higher or lower than the historical trend.

- An analysis of a distributor's capital expenditures for the DSP's forecast period. For capital investments that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of the cost of funds for construction work-in-progress.

- An analysis of capital expenditures in the DSP's forecast period compared to the historical period.

- A summary of any important modifications to typical capital programs since the last DSP (e.g., changes to individual asset strategies). Modifications could also include regulatory drivers (e.g., impacts on capital spending resulting from the December 2024 amendment to the DSC, extending the revenue horizon for residential connections to 40 years and extending the maximum connection horizon to 15 years for housing developments).

System O&M costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. A distributor is expected to consider the reduction in O&M costs when planning capital investments. A description of the impacts of capital expenditures on O&M must be given for each year, or a statement that the capital plans did not impact O&M costs. A distributor must consider the trade-offs between capital and O&M when assessing alternative options to a capital investment.

A statement should be provided that there are no expenditures for non-distribution activities in the applicant's budget.

### 5.4.2 Justifying Capital Expenditures

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based. Filings must enable the OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate identification, optimization, prioritization, pacing of capital-related expenditures, and how it developed its overall capital budget envelope. A distributor should also discuss how its application keeps pace with technological changes and integrate cost-effective innovative investments and traditional planning needs such as load growth, asset condition and reliability.

A distributor must not only provide information to justify each individual material investment, but also the total amount of its proposed capital expenditures. A distributor should provide context on how its overall capital expenditures over the next five years, as a whole, will achieve the distributor's objectives. Particularly, a distributor should comment on lumpy investment years and rate impacts of capital investments in the long-term.

#### 5.4.2.1 Material Investments

The focus of this section is on projects/programs that meet the materiality threshold set out in Chapter 2 of the *Filing Requirements for Electricity Distribution Rate Applications*. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g., unique characteristics; marked divergence from previous trend) are supported by evidence that enables the OEB's assessment according to the evaluation criteria set out below. The level of detail filed by a distributor to support a given investment project or ~~/~~program should be proportional to the materiality of the investment. The guidelines on the information to be provided for any material investment are described in the following sections.

**A. General Information on the project or ~~/~~program**

A distributor is expected to provide information about the investment, which includes the need, scope, volume of work expected to be completed, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the DSC~~Distribution System Code~~, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the benefit-cost analysis results of the recommended alternative. A description of the innovative nature of the investment, if applicable, should also be included.

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of the~~se~~ OEB's Filing Requirements for Electricity Transmission Applications (sections 4.3 and 4.4 in particular).

**B. Evaluation criteria and information requirements for each project/program**

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the investments that are not outputs of the asset management process.

Justifying an investment can be demonstrated through evidence of accepted distributor practices or through a ~~BCA~~ benefit-cost analysis of alternatives~~ as detailed below~~. It is also helpful to show past costs for similar investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including NWSs, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

If a distributor is requesting funding for an NWS, additional guidance on evidentiary requirements is provided in the NWS Guidelines.[24]

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration.

As such, the distributor should fully explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; efficient use of electricity; load management; greater efficiency through grid optimization; lower rates (long-term or short-term); enhanced customer choice (including enabling adoption by consumers of distributed energy resources); or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors may seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

[24] Section 3.2

Where the applicant asserts that a project will support economic growth, the applicant should provide evidence supporting this assertion and an indication of the economic growth policies of the government of Ontario that are relevant to the project.[25]

#### 5.4.2.2 Benefit-Cost Analysis Framework

On May 16, 2024, the OEB issued the OEB's BCA Framework for Addressing Electricity System Needs.[26] The BCA Framework is an OEB policy that outlines the methodology that electricity distributors are to employ to demonstrate the economic feasibility of any NWS or traditional infrastructure solution. The BCA Framework will assist electricity distributors and the OEB in determining whether an NWS, a traditional poles-and-wires infrastructure solution or a combination of the two is the preferred approach in meeting a system need. When NWS are not a suitable option, the BCA Framework can also be used as a form of guidance to assist distributors in justifying their capital expenditures when solely comparing traditional poles-and-wires solutions.

The BCA Framework is an outcome of the Framework for Energy Innovation (FEI) consultation and associated FEI Report[27], initiated to clarify the regulatory treatment of innovative and cost-effective solutions including NWS and facilitate their adoption in ways that enhance value for customers.

The BCA Framework is mandatory when the projected capital cost of the proposed solution to an electricity system need (either NWS or traditional infrastructure) exceeds $2 million (excluding general plant investments). For proposed investments with projected capital costs of less than $2 million, distributors may use existing, alternative cost-effectiveness or decision-making protocols, or the BCA Framework at their discretion.

Before a benefit-cost analysis specifically under the BCA Framework (BCA) is conducted, a distributor should first conduct a pre-assessment to identify whether there is a reasonable expectation that an NWS may be a viable approach to meeting an identified need. Should the pre-assessment conclude that an NWS is a viable approach, a distributor should proceed with completing a BCA. The BCA should be filed along with the pre-assessment results. Electricity distributors may include the BCA as an independent document within its filing or as part of the project business case filed with the OEB.

[25] Applicants may consult the Ontario Regulation made under the Special Economic Zones Act, 2025 for specific criteria related to the determination of long-term economic benefits for Ontario.
[26] EB-2023-0125, May 16, 2024
[27] Ontario Energy Board, Framework for Energy Innovation: Setting a Path Forward for DER Integration, January 2023

BCAs are to be prepared for each specific system need. BCAs are not to be applied on a system-wide basis. However, a single BCA may be used to support a program intended to address multiple, similar needs that may exist at different locations within the distribution system.

The BCA Framework includes two cost-effectiveness tests, the Distribution Service Test (DST) and the Energy System Test (EST). The DST and EST are two separate tests taking two different cost-effectiveness perspectives.

### Distribution Service Test

The DST perspective seeks to optimize the long-term net distribution service benefits for the distributor's customers, as a group. A distributor looking to file a BCA to the OEB must at a minimum employ the **mandatory** distribution service BCA and consider, at a minimum, the mandatory quantitative/qualitative impacts to benefits/costs as outlined in the BCA Framework and provided below for reference. The permitted qualitative impacts should also be included as applicable. The distributor must also include the Excel-based quantitative output template, BCA Data Filing Submission Template, as part of its BCA.[28]

**Table 2 - DST Impact Categories**

| Impact | Mandatory (M) / Permitted (P) | Quantitative | Qualitative |
|---|---|---|---|
| **Benefits** | | | |
| Distribution Capacity (Deferral or Avoidance Benefit) | **M** | **X** | |
| Reliability (Net Avoided Interruption Costs) | **P** | | **X** |
| Resilience (Critical Load Benefits) | **P** | | **X** |
| Innovation & Market Transformation | **P** | | **X** |
| Planning Value | **P** | | **X** |
| **Costs** | | | |
| NWS Acquisition Cost | **M** | **X** | |
| NWS Operations, Maintenance, and Administrative (OM&A) Costs | **M** | **X** | |
| Distribution System Ancillary Services Costs | **M** | | **X** |

[28] Electricity distributors may supplement the template with additional documentation, as they deem necessary.

| | | | |
|---|---|---|---|
| Risk (Distribution System) | **M** | | **X** |

## Energy System Test

The EST perspective seeks to optimize the long-term net benefit of the energy system to all provincial customers. A distributor may choose to include an **optional** energy system BCA and consider, at a minimum, the mandatory quantitative/qualitative impacts to benefits/costs as outlined in the BCA Framework and provided below for reference. While the EST is not mandatory, distributors are encouraged to do an EST particularly if they believe an NWS offers significant benefits beyond those of distribution service. DST impacts should also be included in the EST as the customers taking distribution service from the given electricity distributor are also provincial customers.[29]

**Table 3 - EST Impact Categories**

| Impact | Mandatory (M) / Permitted (P) | Quantitative | Qualitative |
|---|---|---|---|
| **Benefits** | | | |
| DST Benefits | **M** | **X** | |
| Transmission Capacity | **P** | **X** | |
| Avoided Energy Costs | **M** | **X** | |
| Avoided Generation Capacity Costs | **M** | **X** | |
| Reliability (Net Avoided Interruption Costs) | **P** | | **X** |
| Resilience (Critical Load Benefits) | **P** | | **X** |
| Planning Value | **P** | | **X** |
| Innovation & Market Transformation | **P** | | **X** |
| **Costs** | | | |
| DST Costs | **M** | **X** | |
| NWS Acquisition Cost (Incremental to DST costs) | **M** | **X** | |
| NWS OM&A Costs (incremental to DST costs) | **M** | **X** | |
| Energy System Ancillary Costs | **M** | | **X** |
| Risks (Energy System) | **M** | | **X** |

[29] Consistent with guidance in the National Standard Practice Manual, lost revenues are not considered to be a cost or benefit in the DST or EST.

The quantitative cost-effective test(s) and qualitative assessments inform the concluding outcome of the BCA. BCAs that result in a positive net present value (i.e., present value of benefits minus present value of costs) or, equivalently, have a benefit-cost ratio (present value of benefits divided by present value of costs) greater than or equal to 1, will be considered to have a passing score on the DST. Projects that are found to be marginally non-cost-effective may also be considered if the electricity distributor can demonstrate using qualitative impacts and/or an EST that the proposal is still the preferred option to meet a system need.

## Appendix A - System Capability Assessment for Renewable Energy Generation

This appendix is applicable to distributors that have incurred or expect to incur costs to accommodate and connect renewable generation facilities that are eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the *Ontario Energy Board Act, 1998*.

A distributor's investments to accommodate and connect REG (including connection assets, expansions and/or renewable enabling improvements) are part of its DSP. This includes all costs to connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the *Ontario Energy Board Act, 1998*. REG investments can be stand-alone or integrated into a project/program; and are to be categorized for the purposes of section 5.4 in the same way as any other investment.

A distributor should provide information on the capability of its distribution system to accommodate REG investments, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity should also be provided.

In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable) includes:

a) Applications from renewable generators over 10 kW for connection in the distributor's service area

b) The number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the IESO and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown must be provided)

c) The capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area

d) Constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter)

e) Constraints for an embedded distributor that may result from the connections