ONTARIO ENERGY BOARD

Benefit-Cost Analysis Framework for Addressing Electricity System Needs

February 2026

Ontario Energy Board

Table of Contents

1. EXECUTIVE SUMMARY

The *Benefit-Cost Analysis Framework for Addressing Electricity System Needs* (BCA Framework) is an OEB policy that outlines the methodology electricity distributors are to use when assessing the economic feasibility of non-wires solutions (NWS), including distributed energy resources (DERs), to address defined electricity system needs.[1]

The BCA Framework provides a consistent, evidence-based approach for evaluating NWS alternatives to traditional distribution infrastructure. It supports Ontario's Integrated Energy Plan (IEP) - *Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7*, which aims to unlock the value of DERs, lower barriers to participation and enable smarter planning and investment across the energy system. It also informs OEB initiatives aligned with the IEP, including policy guidance on DER incentives, enhanced Demand Side Management (DSM) program design and the development of Distribution System Operator (DSO) capabilities. Ultimately, it supports the delivery of affordable, secure, reliable and clean energy that enables economic growth across the province. The BCA Framework also seeks to reduce regulatory burden by providing the tools that distributors need to easily make business cases for NWS, and to help them account for the full value of their investments.

The BCA Framework is intended for use by electricity distributors to support system planning and distribution rate-setting applications when seeking ratepayer funding for capital investments. It will be incorporated by reference in the OEB's existing Filing Requirements.

The Framework includes two mandatory benefit-cost analyses:

- The Distribution Service Test (DST) which evaluates quantified impacts on the distribution system.
- The Energy System Test (EST), which considers the benefits and costs of an NWS from the perspective of Ontario's electricity system. The EST helps capture the broader value of DERs across the energy system.

Further details on DST and EST are shown in Figure 1.

[1] Per Section 3.2.2, system needs can be defined as discretionary (i.e., a system need where not making any investment could be an acceptable option), or non-discretionary (i.e., a system that needs some investment for an electricity distributor to deliver service to its customers). The approach to conduct a BCA differs depending on whether a system need is considered as discretionary or non-discretionary.

Additional guidance on the use of NWS is provided in the OEB's *Non-Wires Solutions Guidelines for Electricity Distributors* (NWS Guidelines)[2]. The BCA Framework provides more detailed direction for developing the mandatory BCA that is to accompany any application to deploy an NWS.

Figure 1. Core Structure of a BCA

This BCA Framework is divided into five sections:

1. **Purpose and Use:** Provides regulatory context detailing the purpose of the BCA and when it is to be used in support of a rate application.
2. **General Methodological Considerations:** Direction on what to include in the BCA and how to apply what is included.
3. **Cost Effectiveness Tests:** A description of the two cost effectiveness tests and the impacts that they include.
4. **Benefits and Costs:** A detailed description of each of the types of impacts[3] that make up a BCA, whether quantified as part of the cost-effectiveness test, or included as qualitative BCA considerations.
5. **Filing Requirements:** The mandated structure and content of the BCA.

[2] EB-2024-0118, Non-Wires Solutions Guidelines for Electricity Distributors, March 28, 2024

[3] For the purposes of the BCA Framework, an impact may be either a benefit or a cost.

2. PURPOSE AND USE

2.1. Purpose

The BCA Framework[4] provides a consistent, evidence-based approach for evaluating the benefits and costs of NWS. For this Framework, NWS refers to any resource or program, including DERs, located in front of or behind the meter, which could serve as an alternative to traditional electricity distribution infrastructure.

In doing so, the Framework aligns with Ontario's IEP which includes the province's DER Strategy. The DER strategy is built on three pillars, one of which focuses on strengthening grid resilience and efficiency by improving DER integration into system planning frameworks. This involves operationalizing DERs in areas of grid constraint, enhancing system planning and investment decisions, and enabling smarter, more cost-effective grid modernization.

By promoting these objectives, the Framework ensures consistency in how distributors evaluate and choose between NWS and traditional poles-and-wires solutions, ultimately serving the best interests of electricity customers and Ontario's energy consumers more broadly.

In addition, the BCA Framework supports and informs several OEB initiatives that align with the IEP, including but not limited to:

- Margin on Payments Value for Third-Party DERs: uses the BCA to determine eligibility for a margin on payments incentive.[5]
- Review of the Independent Electricity System Operator – Local Distribution Company (IESO-LDC) Working Group Proposal for Stream 2 eDSM Programs: proposes using the BCA to support cost allocation between LDCs and the IESO.[6]
- Work on DSO capabilities, where the OEB's discussion paper highlights the value of standardized approaches to options analysis to ensure DERs are duly considered as solutions to identified system needs.[7]
- Review of the valuation of DERs, which aims to ensure that regulatory and compensation frameworks for DERs appropriately reflect their

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

[5] EB-2025-0083, Framework for Energy Innovation 2.0: NWS Incentives (Margin on Payments)

[6] EB-2025-0156, Electricity demand-side management consultation

[7] EB-2025-0060, DSO Capabilities

system value. The BCA establishes a standardized tool for distributors to assess the value of DERs by defining the costs and benefits for the purpose of requesting rate-funding for using DERs as NWSs. [8]

Note: The BCA Framework is not a substitute or alternative to the Distribution System Code (DSC) Offer to Connect economic evaluation methodology.[9] Electricity distributors must continue to perform economic evaluations using the methodology specified in the DSC. This BCA Framework does not apply to determining costs of expansions and connections in relation to connecting new customers. Such evaluations are governed by the DSC.[10]

2.2. Criteria for Use

Consideration of NWS in Addressing System Needs

Per the OEB's NWS Guidelines for Electricity Distributors (NWS Guidelines), distributors shall incorporate the consideration of NWSs into their distribution system planning process by considering whether a distribution rate-funded NWS may be the preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure.[11]

The NWS Guidelines require distributors to document their considerations of NWSs when making investment decisions on electricity system needs with an expected capital cost of $2 million or more. This requirement applies to distribution system planning, excluding general plant investments. The OEB may reconsider this threshold at a later date.

This does not mean that a BCA will accompany all rate applications to the OEB. 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. The OEB expects that the appropriateness of deploying an NWS will depend on the system need, as some system needs may be clearly unsuitable for NWS.

Currently, the OEB is not establishing a defined approach for the pre-assessment stage.[12] Electricity distributors must file their pre-assessments

---

[8] EB-2025-0268, Review of the Valuation of DERs

[9] Ontario Energy Board Distribution System Code, Appendix B, Methodology and Assumptions for an Offer to Connect Economic Evaluation, October 21, 2009

[10] Ontario Energy Board Distribution System Code, March 27, 2024

[11] EB-2024-0118, Non-Wires Solutions Guidelines for Electricity Distributors, March 28, 2024

[12] The binary screening criteria and technical evaluation stage used in Sections 5.2 and 5.3 of Enbridge Gas' Integrated Resource Planning Framework may be useful guides as to pre-assessment considerations relevant to the consideration of NWS.

with the related applications to the OEB regardless of whether the pre-assessment resulted in the need for a BCA. Should the pre-assessment conclude that an NWS is a viable approach to meeting an identified need, an electricity distributor should proceed with completing a BCA and documenting the results to assess its economic feasibility. This BCA should be filed along with the pre-assessment results.

When a BCA is to Be Completed

This BCA Framework is provided to support the evaluation of the economic feasibility (i.e., benefits exceed costs) of NWS and provides a structured approach to enable electricity distributors to seek ratepayer funding to enable prudent investment in NWS. The BCA Framework allows electricity distributors to demonstrate the economic feasibility of any NWS or traditional infrastructure solution with material costs for which ratepayer funding is being sought through the OEB.

For system needs where an electricity distributor has identified an NWS as a viable option, the electricity distributor is expected to complete a BCA. 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. 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 (i.e., the solution that provides the greatest net benefit) in meeting a system need. Hence the BCA Framework is to be applied symmetrically to traditional poles-and-wire and NWS solutions.

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**. The OEB may reconsider this threshold at a later date. For proposed investments with projected capital costs **less than $2 million**, electricity distributors may use existing, alternative cost-effectiveness or decision-making protocols, or this BCA Framework at their discretion.

2.3. Completing a BCA

The following components are required to complete a BCA for a proposed solution:

- **Description of System Need:** Clearly define the distribution system need(s) that the proposed solution aims to address.

- **Alternative Solutions:** Describe the alternative(s) being considered to meet the identified system need(s).
- **Quantitative Assessments:** There are two quantitative cost effectiveness tests:
    1. **Distribution Service Test (DST)** –Evaluates benefits and costs specific to addressing a distribution system need.
    2. **Energy System Test (EST)** – Evaluates energy system benefits beyond the benefits to the local distribution system. The DST results must be included as inputs to the EST.

  These tests are the primary tool for assessing the economic feasibility of an NWS. **Completing both cost effectiveness tests is mandatory**, using the impact categories specified in Section 5 of this Framework. A mandatory EST enables consistent and accurate assessment of each of distribution and broader energy system benefits and costs, which better supports investment selection that is informed by the beneficiary pays principle. This step in the process better allows distribution customers to bear costs proportional to the benefits to the distribution system while enabling other provincial customers to bear costs proportional to the benefits to the broader energy system. This approach aligns with other OEB initiatives and projects referenced in Section 2.1, which aim to advance Ontario's IEP – particularly by unlocking the value of DERs. It also supports development of IESO conservation programs.

  Templates for documenting the results of the quantitative cost effectiveness tests are provided as live Microsoft Excel-based spreadsheets. These templates must be completed and filed with the OEB for any proposed NWS. They represent the minimum informational filings required when seeking to recover costs through distribution rates. Distributors may submit additional supporting information with their rate application as needed.
- **Qualitative Assessments:** Impact categories not captured as part of the cost effectiveness tests may be included in the BCA through qualitative assessments. A risk assessment must also be completed for the selected solution, including identification of key risks and proposed mitigation strategies.
- **BCA Outcome Summary**: Provide a concise summary of the BCA results, highlighting the preferred solution to the system need identified via the BCA and any associated key considerations applied to complete the BCA.

2.4. Interpreting BCA Outcomes

The DST is to be employed by electricity distributors as part of this BCA Framework. The costs and benefits used for the calculation of the DST will be the primary consideration for assessing distribution rate funding of an NWS. Proposed NWS 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. Only these NWS should be included in applications to the OEB for ratepayer funding, except as noted below.

The passing criteria when using the EST are identical to those of the DST noted above.

Electricity distributors may propose (with supporting rationale) that an NWS which is found to be marginally[13] non-cost-effective, per the cost effectiveness tests, is still the preferred option to meet a system need. The OEB will consider such proposals when there are compelling qualitative impacts that support the deployment of the specific NWS and provide further justification as to the feasibility of a given NWS. Electricity distributors may also indicate in their proposal (with supporting rationale) that a traditional infrastructure solution is still preferred, despite a passing BCA score for an NWS.

2.5. Third-Party Funding

The BCA output is used to support prudent decision-making on whether to proceed with an NWS or traditional capital investment to meet a system need. The BCA Framework does not, on its own, establish requirements for cost responsibility, whether that involves cost allocation between multiple rate-regulated electricity distributors/transmitters, or between electricity distributors, the IESO, and/or other parties.[14]

Electricity distributors are required to consult the IESO on their EST, and are encouraged to determine whether any funding from a third party (including, but not limited to, the IESO) for an NWS is available. This is particularly the case if either the BCA results indicate that an NWS is not cost-effective under the DST (in the absence of any third-party funding) or there are significant bulk electricity system benefits.

[13] The OEB is not defining a specific numerical value as to what would constitute marginal cost-effectiveness.

[14] It is possible that additional policies or adjudicative decisions may make use of the BCA results to determine an approach to cost allocation or cost-sharing in specific circumstances (e.g., a cost-sharing approach between distribution rates and the IESO to fund local electricity demand-side management programs.)

If an electricity distributor is successful in securing funding from a third party, they are to include details of the agreement in their application and only seek to recover the remaining costs from customers. They may also have an opportunity for the NWS to earn revenues through the IESO's wholesale markets, reducing the costs funded through distribution or transmission rates. Either of these circumstances will improve the cost-effectiveness of the NWS under the DST.

It is possible that the IESO may support the input assumptions and the EST outcome of an NWS for which there is no available third-party funding. In such situations, an electricity distributor may still seek recovery of costs through their distribution rates, with both the DST and EST results included in the relevant rate application.

For solutions intended to address regional needs, the OEB will review the costs and associated rate impacts borne by rate-regulated transmitters and electricity distributors net of any funding provided by other sources, as described in the NWS Guidelines.[15]

2.6. Regulatory Submissions

Electricity distributors may utilize the BCA Framework to seek rate funding for NWS or traditional infrastructure investments as part of regular Cost of Service (COS) applications, in conjunction with supporting Distribution System Plans (DSP). Electricity distributors may also utilize the BCA Framework to seek approval for rate funding as part of Incremental Capital Module (ICM) applications.

As per the NWS Guidelines, the OEB will also consider stand-alone applications for NWS outside of rebasing or ICM applications, if necessary. In such cases, the BCA Framework is to be utilized to support these applications.

The choice of regulatory framework or application type should not impact prudent system planning and should not prevent an electricity distributor from using a BCA for projects identified between planned regulatory proceedings.

Distributors should use the BCA Framework for all new project planning activities going forward, including new projects and projects in early stages.

[15] Section 4.3 of the NWS Guidelines

The OEB's expectation is that all rate applications filed in 2026 and beyond should be fully consistent with the BCA Framework.

The OEB will take account of the BCA Framework in its review of rate applications. However, the BCA Framework is not binding on the OEB's determination, which will also consider the circumstances of an electricity distributor's application.

An electricity distributor may only recover costs from its customers, even if an output from the use of the BCA Framework considered benefits that accrue to the broader energy system. For solutions intended to address regional needs, the OEB will review the cost and associated rate impacts borne by rate-regulated transmitters and distributors net of any funding provided by other sources, as described in the NWS Guidelines.[16] Further, the BCA Framework does not apply in determining economic evaluations which are governed by the DSC.[17]

Templates for documenting the results of a benefit-cost analysis are included as part of the BCA Framework. Templates are provided as live Microsoft Excel-based spreadsheets for use by electricity distributors. These templates are to be completed and filed with the OEB for any proposed NWS. The templates are the minimum informational filings when applying for ratepayer funding from the OEB. Electricity distributors may file any supplemental information that may help support their funding request with the OEB.

3. GENERAL METHODOLOGICAL CONSIDERATIONS

As discussed in section 2.2, if an electricity distributor has identified multiple technically viable options (including an NWS) to address a system need and the projected cost of the proposed solution is material, the distributor is required to complete a BCA. 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's concluding outcome is informed by two sets of outputs:

- The cost-effectiveness tests which provide a quantitative assessment

[16] Section 4.3 of the NWS Guidelines

[17] Ontario Energy Board Distribution System Code, Section 3.2, March 27, 2024

of the proposed NWS net benefits to customers.

- The qualitative BCA considerations.

For system needs that proceed to a BCA, electricity distributors are to complete the DST and include consideration of relevant distribution-related qualitative impacts.

Electricity distributors are also to complete an energy system BCA. The quantitative cost-effectiveness test for this BCA is the EST. Energy system BCAs are to address any qualitative considerations specific to the energy system perspective, in addition to the cost-effectiveness test.

This section of the BCA Framework is divided into two sections.

- Section 3.1 focuses on what type of information the electricity distributor should include in its BCA.
- Section 3.2 focuses on how it should present the information included in its BCA.

3.1. What to Include

Each of the sub-sections below address considerations related to the content of BCAs developed by electricity distributors, including:

1. Description of Distribution System Need Being Served
2. Forward-Looking Uncertainty
3. Difficult to Quantify and Qualitative Impacts
4. Symmetrical Treatment
5. Incremental Analysis

3.1.1. Description of Distribution System Need Being Served

Electricity distributors are to include a description of the distribution system need being served in their BCAs. The need being served will define the reference scenario and the potential value of an NWS.

An illustrative (but not comprehensive) list of distribution system needs for which NWS are typically applied is set out below. Each need includes an assessment of value to the bulk energy system as an illustrative example of how a given NWS may deliver value that may be captured by an EST.

- **Forecast Overload Under Blue-Sky Conditions:** Peak load on a circuit is forecast to exceed the acceptable capacity of existing distribution infrastructure. Use of an NWS to reduce load during peak hours can slow peak load growth on the circuit and defer or avoid the need to make the traditional upgrade.
  - *Suitable NWS:* Dispatchable or non-dispatchable NWS, may include energy efficiency, demand response, or distributed energy resources (DER) (storage or generation).
  - *Assessment of Value to Bulk Energy System:* When circuit or distribution asset peak conditions are predictable, many NWS will be able to deliver value to the bulk energy system outside of distribution asset peak conditions.
- **Forecast Overload Under Contingency (N-1) Scenarios:** Some circuits have multiple redundant service lines. These enable power to be continuously provided even if there is a fault along one of the redundant lines (N-1 condition). In this case, load growth on one or more circuits is forecast to impact the electricity distributor's ability to provide service in contingency scenarios.
  - *Suitable NWS:* Dispatchable NWS, may include demand response or DERs (storage or generation).
  - *Assessment of Value to Bulk Energy System:* If NWS capacity is held in reserve for unpredictable scenarios on the distribution system, the value the NWS can deliver to the bulk energy system may be limited.
- **Circuits with Underperforming Reliability:** This need is typically associated with radial circuits that lack redundancy and therefore face frequent interruptions. Here, the approach may be to add redundancy through traditional infrastructure, and an NWS that can provide backup power to maintain service until the cause of an interruption is addressed.
  - *Suitable NWS:* Dispatchable NWS, DER (storage or generation).
  - *Assessment of Value to Bulk Energy System:* If NWS capacity is held in reserve for unpredictable scenarios on the distribution system, the value the NWS can deliver to the bulk energy system may be limited.

3.1.2. Forward-Looking Uncertainty

Electricity distributors may use expected value calculations to account for uncertainty where loss functions are asymmetric. The use of probability estimates and expected value calculations is to assess sensitivity, principally to outcomes outside of an electricity distributor's control. Expected-value calculations may also help electricity distributors more accurately capture the long-term benefits of NWS in aggregate and so provide a better estimate of the value of a given NWS.

Example: Slow Growth Scenario

A distribution asset is approaching capacity, but growth is relatively slow. At the forecast growth rate, an NWS can defer the need for a traditional poles-and-wires upgrade by several years.

Sensitivity to Growth Changes:

- If growth accelerates, the benefit of the NWS may be reduced.
- If growth flattens, the benefit increases significantly, allowing for indefinite deferral of an expansion.

Expected-value calculations may be based on sensitivity analyses or scenario reviews conducted as part of the BCA, or on historical data. Supporting evidence is to be provided for any probability estimates used in expected-value calculations.

3.1.3. Difficult to Quantify and Qualitative Impacts

BCAs include both mandatory and permitted quantitative and qualitative impacts, which are to be included in the relevant cost-effectiveness test and overall BCA, respectively. Table 1 and Table 2 in Section 4.1 identify the mandatory and permitted quantitative and qualitative impacts for the DST and EST, respectively.

Qualitative considerations *can* meaningfully influence the outcome of a BCA. The use of NWS is a relatively recent development in the utility sector, and the technologies and programs that can be used as NWS continue to evolve quickly. In such circumstances, robust estimates of monetary value may not be available for some impacts.

In such cases, the electricity distributor is encouraged to follow the process recommended by the National Standard Practice Manual (NSPM) for documenting non-monetary values in BCAs[18] and provide such qualitative (and where available, quantitative) evidence as is available to support its claim. Even where estimated values are highly uncertain, electricity distributors are recommended to include, rather than ignore them. Estimates that are highly uncertain should be indicated as such.

Qualitative BCA considerations should be specifically tied to the impact categories specified for each type (i.e., distribution service or energy system) and should likewise be specifically tied to one or both types.

3.1.4. Symmetrical Treatment

Asymmetrical treatment of benefits and costs associated with a project can lead to a biased assessment of the net benefits of that project. Impacts should be treated symmetrically when considering benefits and costs.

Example: Avoiding Asymmetry in Cost Treatment

Including host costs would result in an asymmetry that could bias the results of the analysis, as host benefits are explicitly excluded from the EST and DST. If a customer acquires a battery and participates in a program that allows the electricity distributor to control the battery at times of local peak, the DST cost would be limited to the incentive or contract cost paid to the customer for the use of their storage and would not include the costs incurred by the customer to acquire the storage.

3.1.5. Incremental Analysis

In quantifying benefits and costs, BCAs should consider only impacts incremental to the reference scenario that captures the business-as-usual outcome. As part of a BCA, electricity distributors are to articulate the reference scenario in sufficient detail to clearly demonstrate the degree to which impacts are incremental.

Reference scenarios should align with business-as-usual practices. For

[18] See Section C.3 of National Energy Screening Project, National Standard Practice Handbook for Benefit-Cost Analysis of Distributed Energy Resources, August 2020

example, where load growth means that demand on an asset will exceed its capacity, the reference scenario should be the historically standard response of the electricity distributor to addressing such growth.

Appropriately identifying benefits and costs as incremental to the reference case is essential to ensure that impacts are being treated symmetrically and that none are double counted. This is especially important where the NWS makes use of already-existing solutions.

Example: Incremental Analysis Requirement

If an electricity distributor provides customers who already have smart thermostats with incentives to enroll into a demand response program to target a distribution system need, the electricity distributor could not claim any existing energy savings benefits in the EST. These savings would have been delivered without the NWS program.

3.2. BCA Approach Considerations

Each of the sub-sections below address considerations related to the *overall approach* to be used by electricity distributors in developing the content of BCAs, including:

1. Net Present Value / Discounted Cash Flow Analysis
2. Discretionary vs. Non-Discretionary System Needs
3. Study Period
4. Transparency and Validation
5. Projects and Programs

3.2.1. Net Present Value / Discounted Cash Flow Analysis

All benefits and costs included in the cost-effectiveness tests are to be evaluated on a net present value basis, in constant dollars. To maintain alignment IESO guidance for the economic analysis of NWS[19], and to allow for a consistent approach to the valuation of NWS between regional and

[19] Independent Electricity System Operator, *Integrated Regional Resource Plans: Guide to Assessing Non-Wires Solutions*, May 26, 2023

distribution system planning, electricity distributors are to use a real social discount rate of 4% for discounting cash flows to present value, and an assumed inflation rate of 2% for conversions between nominal and constant dollars.

The use of a social discount rate is appropriate for use to capture the time-value of investments; the basis of a social discount rate is consistent with the perspectives of both the DST and EST, which is to maximize the long-term net benefit of distribution service and the energy system for customers (see Sections 4.1 and 4.2). As a result, use of a social discount rate for discounting cash flows to present value is considered best practice. The "long-term net benefit" of distribution service for customers in this case refers to the economic value realized by customers over a time horizon comparable with that used to value traditional poles and wires capital assets. Further, it may be understood to refer to an outcome in which customers receive comparable distribution service at a lower real cost or have access to improved distribution service where the incremental cost is less than the economic value to customers.

An electricity distributor's weighted average cost of capital (WACC) should be used in annualizing the revenue requirement associated with lump-sum capital investments. However, this revenue requirement is then to be discounted at the social discount rate (plus inflation) for the purposes of assessing the benefits to customers of deferring such investments (see Section 5.1.1.1). The WACC should not be used for estimating the net present value of any cost or benefit included in the cost-effectiveness tests.

Where input values used by an electricity distributor were derived using a different inflation rate (i.e., an inflation rate other than 2%), that rate may be used to deflate the input value to constant dollars, and the reasoning for doing so should be included in the BCA documentation. This is not intended to allow for a deviation from the use of the 4% real social discount rate for discounting cash flows to present value.

The DSC sets the minimum conditions that an electricity distributor needs to meet in carrying out its obligations to distribute electricity under its license. The DSC provides direction on the economic evaluation of expansion projects to determine if the future revenue from a given customer(s) will pay for the capital and on-going maintenance costs of an expansion project.[20] The economic parameters (e.g., discount rates) used for these economic evaluations under the DSC may differ from those prescribed in the BCA Framework.

The BCA Framework is the methodology used first to evaluate the different

[20] Ontario Energy Board Distribution System Code, Section 3.2, March 27, 2024

options that an electricity distributor may deploy to meet a defined electricity system need. The DSC's economic evaluation would be used afterwards once a solution has been selected for deployment where a customer contribution is needed.

Table 1. Discount Rates to be used in a BCA

Social Discount Rate	**4%**	Electricity distributors are to use a real social discount rate for discounting cash flows to present value
Inflation Rate	**2%**	Electricity distributors are to use an assumed inflation rate for conversions between nominal and constant dollars
WACC	Electricity distributor specified	

3.2.2. Discretionary vs. Non-Discretionary System Needs

NWS may serve either discretionary or non-discretionary system needs. The type of need being addressed will dictate how certain benefits in the BCA are to be treated. An electricity distributor should indicate whether it has categorized a project as discretionary or non-discretionary, and why.

For the purposes of the BCA Framework, a discretionary system need is one with a reference scenario where not making *any* investment could be an acceptable option. Put differently, a discretionary system need is one where a decision to make no investment will not impact an electricity distributor's ability to deliver service to its customers and meet its regulatory obligations.

For the purposes of the BCA Framework, a non-discretionary system need is one with a reference scenario that needs *some* investment for an electricity distributor to deliver service to its customers and meet its regulatory obligations. For non-discretionary system needs, there is no 'do-nothing' option.

Discretionary Investments

In situations where an electricity distributor is selecting between multiple potential assets to fulfill a discretionary distribution need, cost-effectiveness should be measured by comparing the present value of benefits (net of costs) for each project. The cost of a project should be allocated to that project and not treated as an avoided cost that accrues as a benefit to other projects meeting the same need.

This applies in cases where the electricity distributor is selecting between multiple projects, each of which will provide an approximately equivalent outcome, in terms of addressing a system need. In these cases, the net present value of all alternatives is compared in the BCA, and the option (including the do-nothing option) with the highest benefit-cost ratio is determined to be the most cost-effective solution.[21] This does not prevent a distributor from proposing a project that does not result in the highest benefit-cost ratio, based on qualitative considerations. Electricity distributors are expected to fully explain any qualitative considerations that are used to justify a proposed project that did not result in the highest benefit-cost ratio.

Non-Discretionary Investments

Where an NWS is proposed for the deferral of non-discretionary capital investments, the benefits of the NWS may be considered as an avoided (or deferred) cost of a traditional poles-and-wires solution (i.e., the default reference scenario investment).

Since a BCA is not needed for the default non-discretionary investment, in these cases rather than comparing the net benefits of two alternatives, the BCA assesses the value of the NWS case by comparing its costs against the deferral value of the reference scenario default solution. Care is to be taken to ensure that all benefits and costs considered are truly incremental to the reference scenario.

Impact of NWS Options on Reference Scenarios

There will be some use-cases where a poles and wires solution is impractical and only an NWS is suitable. In these situations, NWS change the reference scenario. In these cases, completing a BCA may be neither appropriate nor necessary.

[21] The net present value of all potential solutions considered by an electricity distributor for a discretionary system need is to be calculated in accordance with Section 4.0 of the BCA Framework. The most cost-effective solution is that with the highest benefit-cost ratio of all potential solutions.

Example: When NWS Becomes Reference Scenario

In some situations, a traditional poles-and-wires solution may be impractical or uneconomic—such as ensuring reliable supply to remote communities located at the end of long radial lines.

Implication: If twinning the line or undertaking another conventional infrastructure upgrade cannot feasibly provide the required level of reliability, a Non-Wires Solution (NWS) may become the reference scenario.

BCA Requirement: In these cases, completing a BCA may be neither appropriate nor necessary. However, the distributor may still choose to complete a BCA if there are multiple NWS to consider.

3.2.3. Study Period

The study period (i.e., the length of time into the future considered by the BCA) should be determined by the alternatives being considered and should generally be sufficiently long to capture the costs and benefits under comparison.

Example: Setting the Study Period for Deferred Investments

In the case where a transformer station upgrade is deferred by five years using an NWS, the study period would extend to the year in which the station upgrade would be fully depreciated. This would allow for a comparison of the net present value of the lifetime annualized cost to customers of the transformer upgrade whether it was installed at the need date, or five years later at the deferred date.

3.2.4. Transparency and Validation

Electricity distributors are expected to complete the filing template (see Section 6) for proposed NWS capital investments that exceed $2 million, subject to any exclusions or pre-assessment results, as noted in Section 2.2. Electricity distributors should ensure that their analysis is transparent, based on robust data and reputable sources, and replicable by others with the same inputs, consistent with the expectations outlined in Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications[22].

3.2.5. Projects and Programs

Electricity distributors may be unable to consider NWS for system needs that necessitate a relatively rapid response. They may be able to consider system needs in aggregate well in advance, but the precise need parameters may be clear only over a short time-horizon (e.g., an electricity distributor may expect significant growth in EV adoption well in advance, but not be able to identify precisely which feeders will be most affected until much later).

Electricity distributors may therefore develop BCAs for proposed *programs* of NWS adoption, that may be used to address multiple (but similar) needs, at different locations within the distribution system.

4. DISTRIBUTION SERVICE AND ENERGY SYSTEM BENEFIT-COST ANALYSES

Electricity distributors are to include a distribution service analysis (i.e., DST inputs and results, and consideration of any distribution service qualitative factors) in their filings to the OEB when requesting ratepayer funding for NWS. They are also to include a separate energy system test and its results. Electricity distributors are to include an assessment of distribution service options in their filings, in accordance with the BCA Framework. For each BCA included, the electricity distributor is to quantitatively assess cost-effectiveness using the relevant cost-effectiveness test and identify any other qualitative BCA considerations.

This section of the BCA Framework defines the two relevant cost-effectiveness tests when considering NWS. It describes the purpose, perspective and impacts of each test, and provides some context for evaluating outcomes. Lost revenues are not considered to be a cost or benefit in the DST or EST. This is consistent with guidance in the NSPM[23] to separate cost-effectiveness analysis from rate impact analysis.

All applications submitted by electricity distributors for the use of NWS are to include calculations of the benefits and costs prescribed by the DST, and the

---

[22] Ontario Energy Board, *Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications*, December 2022

[23] National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, August 2020, Appendix A.2

benefits and costs prescribed for the EST.

The DST and EST are two separate tests taking two different cost-effectiveness perspectives. They are not additive.

The cost-effectiveness tests of the BCA Framework differ from traditional CDM cost-effectiveness tests used in Ontario. The DST evaluates the benefits and costs of a distribution service change due to implementing an NWS. The EST evaluates whether provincial ratepayers as a whole will be better off from the implementation of an NWS. In Ontario's case, the DST focuses on maximizing the long-term net benefits to the distribution service provided to an electricity distributor's customers, as a group, whereas the EST focuses on maximizing the long-term net benefits to energy system customers more broadly.

It is this perspective that defines what impacts are viewed as acceptable (or not) to include in each of the tests. Host benefits (e.g., customer energy benefits), for example, are not appropriate for inclusion. Including energy benefits that are realized by individual customers as benefits in the test implicitly allocates the costs of attaining those individual benefits across (in the case of the DST) all distribution service customers. Projects with host benefits are still subject to the BCA Framework, however, the host benefit itself cannot be considered as an input to the analysis.

4.1. Distribution Service Test

The DST evaluates the impacts associated with providing distribution service, favouring the solution that delivers the highest net benefits to the distribution service enjoyed by the electricity distributor's customers. It does so by comparing the costs of distribution service to the benefit of the distribution service.

The perspective of the test is therefore one that seeks to optimize the long-term net distribution service benefits for the electricity distributor's customers, as a group.

A passing score on the DST is necessary unless other qualitative benefits warrant proceeding with the NWS. An electricity distributor should only pursue NWS options where the present value of distribution service costs declines or where cost increases are justified by improvements to distribution service. Consideration of changes to service costs should take a long-term perspective, given the life of most distribution assets.

Table 1 categorizes each distribution service benefit and cost in two ways, whether inclusion of the benefit or cost is:

- **Mandatory or permitted**: An impact is to be included in the BCA (either in the cost-effectiveness test or as a qualitative BCA consideration) if the table indicates it as such.

- **Expected to be quantitative or qualitative:** Qualitative benefits and costs may be addressed as considerations within the BCA but may not be included in the cost-effectiveness test.

Quantitative impacts are to be included in the DST and some qualitative impacts are mandatory in the BCA, whereas others may be included as considerations. Electricity distributors are mandated to provide a quantitative estimated value in the DST for all impacts listed as "quantitative".

Table 2. DST Impact Categories

Impact	Mandatory (M) / Permitted (P)	Quantitative	Qualitative[24]
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
Risks (Distribution System)	M		X

[24] Electricity distributors are permitted to provide quantitative estimated values for impacts listed as qualitative, and include those in the DST, if they have the means to do so.

4.2. Consideration of Societal and Non-Energy Benefits

An NWS may provide non-energy benefits to society, an electricity distributor and/or its customers. Non-energy benefits that an NWS may deliver include environmental, economic and social benefits.

These potential impacts are broad and varied, making them difficult to quantify or qualify, hence, they are accounted for in the BCA Framework with a non-energy benefit (NEB) adder.

Since 2014, cost-effectiveness tests in Ontario – for both natural gas DSM under the OEB's DSM Framework and electricity conservation and demand-side management programs delivered by the IESO – have incorporated a 15% adder to account for non-energy benefits, such as environmental, economic and social benefits.[25]

Consistent with this approach, an electricity distributor may apply a 15% NEB adder to the quantified benefits considered as part of the benefit-cost ratio output of the DST. The NEB adder is only to be incorporated for NWS that align with the definition of eDSM (electricity conservation and demand-side management) from the Minister's Directive to the IESO dated November 7, 2024 which is used in the current Ontario eDSM Framework.[26] No societal or NEB adder is to be incorporated for any other type of NWS investment.

4.3. Energy System Test

The EST evaluates the impacts to all customers in Ontario, identifying the solution that delivers the highest net energy system benefits to these customers. The EST considers the benefits and costs associated with a given NWS from the perspective of the bulk Ontario electricity system.

The perspective of the test is one that seeks to optimize the long-term net benefit of the energy system to all provincial customers.

The rationale for the test is to promote solutions that lower overall electricity costs for Ontarians. Costs and benefits not derived directly from the impact of the NWS on the cost of the energy system to Ontario customers are not considered.

It is expected that the electricity distributor will consult with the IESO when completing the EST.

---

[25] Ontario Energy Board, Report of the Board, December 22, 2014, section 9.2 and the Independent Electricity System Operator, Cost Effectiveness Guide for Energy Efficiency, May 16, 2022, Appendix A

[26] Directive to the Independent Electricity System Operator, November 7, 2024, section G

Table 3 shows mandatory and permitted energy system impact categories, identifying those that are qualitative versus quantitative. Electricity distributors are expected to quantify those impacts identified as quantitative in line with the direction provided in Section 4.1 above. DST impacts should also be included in the EST, as the customers taking distribution service from the given electricity distributor are also provincial customers.

If an electricity distributor identifies permitted impacts that can be quantified, they may be considered for inclusion in the EST's quantitative cost effectiveness calculation. Otherwise, qualitative assessments of impact categories may be included to provide further support for a given solution that might be marginally non-cost effective from the perspective of the EST quantitative cost effectiveness calculation.

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

The distributor should confirm with IESO whether an NEB is applicable to bulk system benefits and ensure there is no risk of double counting NEBs in the DST and EST. If the IESO confirms that an NEB is applicable for the bulk system benefits, the IESO will inform the LDC of the appropriate NEB value. If the IESO confirms that an NEB is not applicable to bulk system benefits, a 15% NEB adder may still be applied to the DST component of the EST, for NWS that align with the definition of eDSM in the Ontario eDSM Framework.

5. BENEFITS AND COSTS

This section is divided into two sections.

- Section 1 addresses the benefits and costs considered by the distribution service BCA.
- Section 2 addresses the benefits and costs considered by the energy system BCA.

Where a benefit or cost is a series of annual values, these are to be deflated to the dollar year in which the analysis is undertaken, discounted at the social discount rate, and summed to deliver a net present value which may be included in the given cost-effectiveness test.

5.1. Distribution Service Benefits and Costs

Electricity distributors may use the methods recommended below to estimate values for the test. They may also propose alternative methods for estimating these values, but should be prepared to justify their choices within the context of the perspectives and goals of the DST and general considerations identified in Section 2.1.

Not all impacts are expected to be relevant for all BCAs. Depending on the underlying system need and the NWS identified to meet that need, some impacts may be inapplicable, negligible, duplicative with other impacts, or difficult to quantify.

Table 4. Applicability of DST Impacts

Impact	Description	Considerations for Applicability
BENEFITS		
Distribution Capacity (Deferral or Avoidance Benefit)	Accounts for the benefits associated with the deferral or avoidance of the need for traditional infrastructure deployment resulting from the adoption of the NWS	This should include both the avoided or deferred initial costs as well as the operations and maintenance of the traditional poles and wires solution.
Reliability (Net Avoided Interruption Costs)	Accounts for customer interruption costs due to a reduction in frequency and duration of	For some NWS, this benefit will not be applicable. For NWS such as energy storage and dispatchable DG with islanding capabilities, this benefit may be applicable if

	interruptions, primarily associated with the value of lost load	the NWS enables customers to operate in islanded mode while the distribution system interruption is being addressed. It may be possible that the NWS is used in a manner that would prevent interruptions from occurring and do so to a greater extent than the reference case / traditional upgrade. In such cases, there also may be some benefits from avoided restoration costs.
Resilience (Critical Load Benefits)	Accounts for value of serving critical loads during prolonged system interruptions	If an NWS can provide backup power for prolonged interruptions, then there may be resiliency benefits, particularly if the loads served provide critical community services.
Innovation & Market Transformation	Accounts for potential future benefits resulting from broader program or market development that is supported by the proposed investment	This set of benefits is often related to pilot and demonstration projects which can provide significant learning value to inform more significant future investments or programs. This set of benefits may also include OM&A savings from investments to improve customer service, or OM&A savings associated with the adoption of advanced metering capabilities to enable the NWS.
Planning Value	Accounts for the option value to support electricity distributor planning	NWS often provide option value that can help electricity distributors to manage costs and uncertainty, particularly uncertainty related to load growth. For example, the deployment of an NWS may allow for the deferral of a capital-intensive infrastructure solution until a time where there is more certainty around future load needs.
COSTS		
NWS Capacity Acquisition Cost	Cost includes the cost to acquire, connect, and dispatch the NWS capacity needed to meet the need that would otherwise be met with a traditional poles and wires solution.	The nature of these costs may vary depending upon the type of NWS and the method of acquiring NWS capacity. Costs in this category may also include costs of monitoring and dispatching NWS associated with the NWS, and the incremental distribution equipment to be able to safely interconnect the NWS.
NWS Operations, OM&A Costs	Costs to manage and maintain the NWS project or program. This includes any distribution system maintenance costs specific to the	Examples of relevant costs include incremental costs for third-party contractors and/or utility staff, relative to such costs for the reference case, for: • Program administration • Sales & marketing

	operation of the NWS.	• Resource procurement (only costs to manage procurement; excludes NWS Capacity Acquisition Cost) • Measurement & verification
Distribution System Ancillary Services Costs	Incremental costs to the electricity distributor associated with increased needs for ancillary services due to the adoption of NWS	This impact may be applicable if as a result of the NWS, the electricity distributor makes investments to manage power flow issues. For example, deploying distributed solar as an NWS may result in greater investment in voltage control capabilities on the circuit. Electricity distributors should take care to avoid duplication with other impacts (e.g., NWS Capacity Acquisition Cost, etc.)
Risks (Distribution System)	Accounts for uncertainty which may present schedule, cost, or performance risk	For NWS, this consideration may be necessary to include as the downside counterpart to the upside Planning Value.

5.1.1. Distribution Service Benefits

This section describes each of the benefits identified for consideration in the DST and the recommended approach for estimating the value of these benefits for those where quantification is expected.

5.1.1.1. Distribution Capacity (Deferral or Avoidance Benefit)

Electricity distributors are to quantify, as a part of the DST cost-effectiveness test, the estimated benefit of NWS adoption due to traditional distribution capacity need deferral or avoidance.

The primary distribution system use-case and the primary driver of value for the DST test is the benefit that comes from deferring or avoiding the costs of deploying traditional poles and wires solutions. There are two recommended approaches to quantifying this value:

- **Cost of service** – accounts for the avoided incremental increase in annual revenue requirement as a result of deferring the traditional investment. Preferred when the value is tied to a discrete and specific need.

- **Marginal capacity value** – accounts for the incremental value of NWS capacity on constrained circuits. Preferred when the need is not precisely tied to a specific asset.

Cost of Service

This approach is useful for the deferral or avoidance of a specific traditional investment with a project-specific cost and predicted deferral timeframe. The benefit value may be estimated according to Equation 1.

Equation 1. Avoided Distribution Capacity Cost of Service

$$benefit_{y=p} = NPVCoSreference_{y=p} - NPVCoSdeferred_{y=p}$$

Where the y subscript identifies the given year, and when $y = p$ this refers to the present year (in which the analysis is being undertaken), and,

$$NPVCoSreference_{\,y=p} = \sum_{y=needDate}^{Yref} \frac{RevRequirementRef_y}{(1 + inflation + socialdiscount)^{(y-p+1)}}$$

$$NPVCoSdeferred_{y=p} = \sum_{y=deferredDate}^{Ydefer} \frac{RevRequirementDef_y}{(1 + inflation + socialdiscount)^{(y-p+1)}}$$

Where the primary difference between the two net present values (NPVs) will typically be the set of years covered by the life of the traditional poles and wires asset, which begins in year $needDate$ in the reference scenario and the year $deferredDate$ in the scenario in which deferral is applied.

The period of the analysis should extend through to the end of year $y = Ydefer$, the final year of the traditional solution's life if it is deferred. If the need is avoided entirely the period of the analysis should extend through to the end of year $y = Yref$, the final year of the traditional solution's life in the reference scenario. Other variables are defined below.

Table 5. Avoided Distribution Capacity Cost of Service Parameters

Parameter	Definition	Source	Note
$NPVCoSreference_{\ y=p}$	Net present value of the cost of service of the traditional solution in the year in which the analysis is being completed $(y = p)$ <u>for a solution installed at the reference scenario need date</u> $(y = needDate)$.	Calculated	The value should be expressed in constant dollars of the year in which the analysis is being completed.
$NPVCoSdeferred_{y=p}$	Net present value of the cost of service of the traditional solution in the year in which the analysis is being completed $(y = p)$ <u>for a solution installed at the deferred need date</u> $(y = needDate)$.	Calculated	If the traditional solution is being avoided altogether this value may be zero.
$RevRequirementRef_y$	The revenue requirement derived from the capital and OM&A costs of the traditional solution, <u>deployed at the reference need date</u>, in year *y*	Calculated, Planning Values	The capital cost of the traditional investment should be justified based upon planning estimates which account for the project- and location-specific capital costs for deploying the traditional infrastructure. The revenue requirement should be calculated based on this capital cost, consistent with the OEB's Cost of Service Filing Requirements.[27] Simplifying assumptions should be documented by the electricity distributor in its BCA. Annual OM&A costs may be included in this value.

[27] Ontario Energy Board, *Filing Requirements for Electricity Distribution Rate Applications – 2022 Edition for 2023 Rate Applications – Chapter 2: Cost of Service*, April 2022

$RevRequirementDef_y$	The revenue requirement derived from the capital and OM&A costs of the traditional solution, deployed at the deferred need date, in year *y*	Calculated, Planning Values	As above for the revenue requirement under the reference scenario but reflecting any assumed changes in capital cost or other inputs to the calculation of the revenue requirement resulting from investment deferral.
$inflation$	Constant, assumed to be 2%	IESO, IRRP Guide to Assessing NWAs[28]	Assumed inflation should be consistent with the most current value in use by the IESO
$socialdiscount$	Constant, assumed to be 4% - real (not nominal)	IESO, IRRP Guide to Assessing NWAs	Assumed social discount rate should be consistent with the most current value in use by the IESO

Electricity distributors may choose to apply some simplifying assumptions for the purposes of estimating the annual revenue requirements associated with the traditional poles and wires investment. The electricity distributor should document what simplifying assumptions have been applied.

This approach is most suitable when benefits are tied to the deferral or avoidance of a specific need (e.g., the deferral of a transformer station upgrade). The estimated NWS benefits derived using Cost of Service methods may be more accurate than those estimated using the marginal capacity value approach described below.

Marginal Capacity Value

This approach is useful for more programmatic investments which are not tied to a single, specific traditional investment. This approach is similar to calculating marginal distribution capacity value for other types of programs. The annual benefit value may be calculated according to Equation 2, which is further described in Table 4:

Equation 2. Avoided Distribution Capacity Infrastructure

$$Benefit_y = \frac{\Delta PeakLoad_{y,r}}{1 - Loss\%_{y,D\rightarrow r}} \times DistCoincidentFactor_y \times DeratingFactor_y \times MarginalDistCost_y$$

[28] Independent Electricity System Operator, *Integrated Regional Resource Plans; Guide to Assessing Non-Wires Alternatives*, May 2023

Where, the sub-script *r* refers to the retail delivery or connection point for the NWS and the sub-script $D \rightarrow r$ refers difference in location between the distribution system constraint and the retail delivery or connection point of the NWS.

For the purposes of cost-effectiveness testing, the series of annual values estimated using the equation above are to be aggregated into a net present value in constant dollars of the year in which the analysis is being undertaken, using the social discount rate prescribed by the IESO in its Guide to Assessing NWAs[29].

The other variables are defined Table 6, below.

Table 6. Avoided Distribution Capacity Infrastructure Parameters

Parameter	Definition	Source	Note
MarginalDistCost	Marginal cost ($/kW-yr or $/kVA-yr) of the distribution equipment from which the load is being relieved in year *y*	Program-specific	Localized, equipment-specific marginal costs of service defined by the program need should be used in most cases.
ΔPeakLoad	Nameplate demand reduction of the project at the retail delivery or connection point *r*	NWS-specific	Positive value represents a reduction in peak load. The timing of benefits realized from peak load reductions are project- and/ or program-specific.
Loss%	Loss percent between the location of the distribution system constraint (*D*) and the retail delivery or connection point (*r*) for the NWS.	Program-specific	This value is used to adjust the *ΔPeakLoad* (MW) impact at the location of the system constraint relative to the NWS location as a result of distribution losses, if relevant.
DistCoincidentFactor	Input that captures the contribution to	Program-specific	For example, a nameplate demand reduction of 100 kW on the distribution feeder with a

[29] Independent Electricity System Operator, *Integrated Regional Resource Plans; Guide to Assessing Non-Wires Alternatives*, May 2023

	the distribution element's peak relative to the project's nameplate demand reduction.		coincidence factor of 0.8 would contribute an 80 kW reduction to peak load on an element of the distribution system
DeratingFactor	A factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours.	NWS-specific	For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence of a solar array which could limit its peak load reduction contribution on an element of the distribution system.

Electricity distributors do not need to exactly replicate the approach defined above. The critical inputs of any approach used by an electricity distributor are:

a) **Demand Impact.** An estimate of the impact on demand that the NWS can be expected to deliver in the periods in which demand typically drives investment needs for the relevant type of asset (or group of assets).

b) **Average Marginal Cost.** An estimate of distribution service benefit per kW of demand reductions delivered with the timing and frequency assumed as part of the demand impact estimation process.

Example: Estimating Marginal Costs from EV Adoption Projections

An electricity distributor has procured an EV adoption study, which provided a probabilistic locational projection of EV adoption over the next 20 years. The electricity distributor has used this to develop a projection of the approximate magnitude of investment to address incremental system needs in the areas of highest projected EV growth over the next five years. These values can be used to estimate a levelized cost of incremental EV loads (in terms of $/kW-year), which can then be used as a basis for an estimated average marginal cost (after appropriate de-rating, etc.).

5.1.1.2. Reliability (Net Avoided Interruption Costs)

Electricity distributors are permitted to identify any anticipated reduction to net avoided interruption costs to customers because of NWS implementation.

Care should be taken to ensure only those benefits appropriate to the DST are considered. Net avoided interruption costs are considered an appropriate distribution service benefit when they can reasonably be claimed to accrue to all customers directly affected by the NWS. In cases where this benefit is realized only by the host of the DER, and not by the other customers affected by the NWS deployment, it is to be considered a host benefit and not included as a benefit in the BCA.

Reliability benefits may be claimed when it can be reasonably shown that the NWS will improve the electricity distributor's response to disturbances and faults in the distribution system.

In articulating considerations of reliability benefits, it is important to consider the distribution of interruption events, not just average interruption statistics, when considering impacts.

Electricity distributors confident in their assessment of the reliability benefits and equipped with a robust estimate of the impact of the NWS on the relevant metric for customer interruptions may apply estimated values of metric improvement to an estimate of the value of lost load to customers in the area affected. The value of lost load (particularly for locationally specific areas) should be estimated specifically for the affected location in most cases, but in some instances the use of more generic values may be acceptable. The OEB's Vulnerability Assessment and System Hardening Report may also be referenced to provide guidance when estimating the value of lost load[30].

NWS can sometimes provide ancillary services that support distribution system reliability. To include this benefit, the electricity distributor is to demonstrate that there is a need and value for ancillary services which would need to be addressed regardless of the NWS. It may ultimately serve to lower the cost of the NWS because other solutions may not need to be deployed, but it does not generate a net benefit relative to reference case.

In some cases, the use of NWS may reduce the reliability of the distribution system. This may occur when the traditional poles and wires solution deferred by the NWS was planned to incorporate some measure to improve reliability, or when the NWS impacts reliability directly, necessitating some remedial action. These issues should be addressed either in the estimation of NWS acquisition or OM&A costs, or else, if no remedial action is anticipated, then as a qualitative consideration.

5.1.1.3. Resilience (Critical Load Benefits)

Electricity distributors are permitted to identify any anticipated improvement in distribution system resilience from NWS implementation.

Resilience and reliability are closely related, and care should be taken by electricity distributors to avoid double-counting benefits. Where ambiguity exists as to whether a benefit can be characterized as reliability or resilience, the electricity distributor should note this and identify the category to which benefit is being assigned.

Electricity distributors are to ensure that any resilience improvements being considered are distribution service improvements and not host resilience improvements.

The value here should consider only incremental benefits beyond the reliability benefits associated with the value of lost load and consider benefits that are unique to prolonged interruption events.

To the extent that electricity distributors may be able to estimate the value of these impacts, it is important that electricity distributors clarify the approach and key assumptions used in estimating a value for resilience. These

[30] EB-2024-0199, Vulnerability Assessment and System Hardening Report, October 7, 2025

benefits, and the approach for calculating them, may differ significantly based upon the critical loads served (e.g., emergency services, fueling stations, grocery stores, shelters).

5.1.1.4. Innovation & Market Transformation

Electricity distributors are permitted to identify any anticipated benefits that the NWS implementation may provide for market development or in supporting innovation that will result in lower-cost distribution service in the longer term.

The benefits of innovation and market transformation identified in the BCA considerations are those that specifically improve the value of distribution service to customers over time. It is insufficient to only claim that the proposed NWS implementation will help to accelerate the adoption of a given type of NWS in the electricity distributor's service territory, normalizing the equipment, and transforming the market. To claim that there is a distribution service benefit to this market transformation, a case needs to be made that accelerated adoption of a given type of NWS will reduce the capacity acquisition costs for future NWS deployments.

Claims of innovation benefits are to be aligned with the treatment of innovation costs included in the cost-effectiveness test. As noted in Section 5.1.2, electricity distributors may request that some costs be excluded or adjusted within the BCA if they are not reflective of unit costs at scale (e.g., in the case of a pilot). In such cases where innovation costs are excluded from the cost-effectiveness test, electricity distributors may not also claim consideration of innovation or market transformation benefits in the larger BCA.

5.1.1.5. Planning Value

Electricity distributors are permitted to identify any anticipated benefits that NWS implementation may provide in terms of its planning or option value. Planning value captures some of the benefits that an NWS may offer for addressing various uncertainties inherent in distribution planning.

Planning value refers to the option value derived by providing an electricity distributor additional time to find other, less costly solutions to the distribution system need before committing to capital investment that may lock in costs to the distribution system over the long-term.

These benefits are likely to be difficult to quantify and therefore, electricity distributors may identify this value as a qualitative consideration within the BCA.

If the electricity distributor has confidence in its understanding of the key uncertainties, it may elect to quantify these benefits. Should the electricity distributor wish to quantify the benefits of planning value, it may wish to do so by considering probabilistic outcomes for deferral benefits. If doing so, the electricity distributor should also consider the downside risk (see Section 5.1.2.7).

5.1.2. Distribution Service Costs

This section describes each of the cost categories identified for consideration in the distribution service BCA, either as quantitative costs included in the DST, or as qualitative BCA considerations. Quantified costs included in the DST should be converted into an annual revenue requirement in nominal dollars (i.e., incorporating inflation assumptions into future costs where appropriate). The electricity distributor will also clarify which costs would be treated as capital and which costs treated as OM&A for ratemaking purposes,[31] and convert capital costs into an annual revenue stream, taking into account the depreciation period, WACC, and taxes. The NPV of all quantified costs should then be calculated, using the approach discussed in calculating the value of avoided distribution capacity in section 5.1.1.1 to discount future costs and convert from nominal to constant dollars.

5.1.2.1. NWS Acquisition Costs

Electricity distributors are to quantify, as a part of the DST cost-effectiveness test, the estimated costs of acquiring the NWS under consideration as part of the BCA.

This category includes all costs related to acquiring the NWS capacity necessary to supply the identified need *that impacts customer distribution service.* Given the unique nature of each need, the electricity distributor will need to apply judgement in identifying the appropriate costs for inclusion and careful consideration of:

a) **The goal of the test** is to identify NWS options where distribution service costs decline or are justified by improvements to distribution service with the understanding that cost impacts to distribution customers are determined on a net present value basis.
b) **The symmetrical treatment of incremental costs and benefits**.
c) **The principle that costs follow benefits** (i.e., a cost is appropriate

[31] The FEI Report notes that associated capital and OM&A costs for NWS would be treated in the same manner as costs for other distribution activities.

for inclusion only if it can be demonstrated that it is associated with the delivery of distribution service benefits included in the BCA), and that it is incremental to costs already included in the reference scenario.

NWS acquisition costs may include costs such as:

- **Contracting Costs.** Costs of procuring capacity from third parties. A BCA should include all the incremental costs incurred by the electricity distributor to acquire and dispatch the capacity. For the specific example of third-party renewable generation capacity, only the direct payments under a contract between the electricity distributor and the renewable generators (and any associated dispatch and administration costs) should be considered under the BCA.
- **Incentive Costs.** Payments to individual third parties.
- **Equipment and Systems Costs.** Costs for procuring equipment (load control equipment, storage, etc.) and the systems (software, hardware, training) necessary to effectively dispatch NWS at times of distribution system need.

This is not intended to be a comprehensive list. Acquisition costs for the DST should generally *not* include host costs, energy costs, or any other costs which cannot be reasonably construed as impacting the long-term distribution service value derived by customers served by the applicant electricity distributor.

Where the distributor incurs material capital costs to implement the NWS (e.g., in a case when the distributor builds the DER itself instead of contracting with a third party), it should calculate the annual appropriate revenue requirement and apply this annual series of costs in the test.

In assessing what costs to include in the BCA, electricity distributors are to carefully consider what costs are truly incremental to the reference scenario. This is particularly the case in the larger context of the electricity distributor's long-term strategy to respond to the set of planning uncertainties referred to as the "energy transition" (e.g., electrification, growth of behind-the-meter self-generation, extreme weather events, etc.)

The costs of enabling infrastructure to manage and control DERs deployed as NWS should be excluded from BCA costs unless they can be demonstrated as being unique for the given project. The acquisition of systems to coordinate the wide-scale deployment and dispatch of DERs, for example, should be considered a market or capability development cost, and not attributed to an individual project. Likewise, where it can be demonstrated that they are a prudent investment irrespective of the project or program for which the BCA is being developed, the costs of distribution system modernization, such as Fault-Locating Isolation and Service Restoration (FLISR) or Volt-Var Optimization (VVO) should be excluded from the BCA.[32]

The OEB may assess the proposed costs included in each BCA on a case-by-case basis and assess the appropriateness of their inclusion or exclusion on the basis of the symmetrical treatment of incremental costs and benefits and the principle that costs follow benefits, in addition to the general considerations laid out in Section 2.1.

The DST should include the net present value of NWS acquisition costs based on the social discount rate specified in Section 3.2.2, in constant Canadian dollars of the year in which the analysis is being conducted (or will be submitted) using the assumed inflation rate from the same section.

5.1.2.2. NWS OM&A Costs

Electricity distributors are to quantify, as a part of the DST cost-effectiveness test, the estimated costs of operating and maintaining the NWS under consideration, as well as incremental administrative costs, including the costs of EM&V.

This category includes all the costs related to ensuring the ongoing availability of the NWS and to fulfilling all legal and regulatory obligations the electricity distributor incurs through its operation.

Electricity distributors are to categorize all incremental OM&A costs. Categories used for Cost of Service applications may be used, but at a minimum, OM&A costs should be categorized as either operations, maintenance, billing and collecting, community relations, or administrative and general.[33] Electricity distributors may include additional incremental OM&A cost categories that may be applicable for a given project. Electricity distributors may support their choice to include additional OM&A costs on the basis of the symmetrical treatment of incremental costs and benefits and the principle that costs follow benefits.

Electricity distributors incurring EM&V costs beyond the standard that might be expected of a mature NWS in an established market may recommend that incremental EM&V costs intended to support longer-term market development be excluded from the cost-effectiveness test. Such excluded costs should still be documented in the BCA, however under the “BCA Considerations” section (see Section 6.1).

---

[32] Where such costs are excluded, distributors should take care to ensure that any associated benefits are also not attributed to the project or program for which the BCA is being developed.

[33] OEB Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications, Chapter 2 Cost of Service, Section 2.4.2, December 15, 2022

Electricity distributors should note that exclusion of such market development costs from the cost-effectiveness test will also (under the principle of symmetry) necessitate the exclusion of corresponding innovation or market transformation benefits.

The OEB may assess the proposed costs included in each BCA on a case-by-case basis and assess the appropriateness of their inclusion or exclusion on the basis of the two principles identified above and their adherence to the general considerations laid out in Section 2.1

The DST should include the net present value of NWS OM&A based on the social discount rate specified in Section 3.2.2, in constant Canadian dollars of the year in which the analysis is being conducted (or will be submitted) using the assumed inflation rate from the same section.

5.1.2.3. Distribution System Ancillary Services Costs

Electricity distributors are to identify any anticipated impact on distribution system ancillary service costs. Where these costs are material, they should be included in the DST as a quantitative input. Where these costs are uncertain but believed to be modest, they should be included as qualitative inputs to the BCA but may be excluded from the DST calculation.

Distribution system ancillary services may include, but is not limited to, voltage regulation, harmonic control, frequency management, and reactive power management.

5.1.2.4. Risks (Distribution System)

Electricity distributors are to identify the key risks that may impact the net benefits estimated as part of the cost-effectiveness test or the qualitative BCA considerations.

For each quantitative cost or benefit included in the cost-effectiveness test, electricity distributors are to identify the key uncertainties associated with the projected value, and the risks these pose to outcomes and customer distribution service value. Outcome risks should be accompanied by a qualitative assessment (e.g., unlikely, very unlikely, etc.) and some justification from the electricity distributor for that assessment.

5.2. Energy System BCA Benefits and Costs

This section describes the categories of benefits and costs that are part of an energy system BCA. Because the perspective of the energy system BCA is to identify solutions that maximize the long-term net benefits to energy system customers, it should include many of the impacts and considerations included in the distribution service BCA.

The section below therefore focuses on incremental impacts relative to the distribution service BCA, simply noting where impacts from the distribution service BCA and DST should also be included in the energy system BCA and EST.

It is expected that in most cases, the impacts (costs and benefits) used for the DST will be a sub-set of the benefits and costs used for the EST, but this may not always be the case (e.g., it is possible that some NWS impose costs on the broader electricity system without decreasing the value of distribution service). For this reason, the benefits of the two tests should not be summed for the purpose of a collective BCA across both perspectives, as doing so risks double-counting.

IESO Support for Energy System Inputs

It is expected that the electricity distributor will consult with the IESO for support in selecting EST input values. The most accurate data source for EST input values should be identified through engagement between the electricity distributor's regional planning Technical Working Group (TWG) Subject Matter Expert and their TWG counterpart at the IESO. This may include the following (in general order of preference):

1. From an active regional planning TWG
2. From published regional planning information
3. From an Annual TWG meeting
4. Direct engagement between the electricity distributor's planning team and the IESO's regional planning team

The sources used for input values to the EST are to be clearly documented in the completed BCA. **The OEB expects that any BCA with a completed EST will include a Letter of Comment from the IESO.** The IESO Letter of Comment is completed following the completion of the electricity distributor consultation with the IESO. It may include the IESO's position on both the quantitative and qualitative impacts considered by an electricity distributor in its application to the OEB.

For the EST, the electricity distributor should confirm with IESO if the NEB is applicable to the bulk system benefits and ensure there is no double counting. If the NEB is not applicable, it may still be applied to the DST component of the EST.

5.2.1. Energy System Benefits

This section describes each of the benefits identified for consideration in the energy system BCA, including where quantification is expected for the EST.

Default province-wide sources for some energy system benefits (avoided energy and avoided generation capacity) are provided. As described above, it is expected that the electricity distributor will consult with the IESO for support in selecting EST input values.

The IESO may provide more accurate and location-specific values for these benefits, but the default sources described below may be useful at the planning stage to provide an initial estimate of the EST results, prior to consulting with the IESO.

5.2.1.1. Distribution Service Test Benefits

The customers of the implementing electricity distributor are a sub-set of the larger group of provincial energy system customers. It is therefore appropriate to include in the EST all the benefits included in the DST.

5.2.1.2. Transmission Capacity (Deferral or Avoidance Benefit)

Electricity distributors are permitted to quantify, as a part of the quantitative EST cost-effectiveness test, the estimated benefit of NWS adoption due to reductions of peak demand imposed on upstream transmission assets. A province-wide value for avoided transmission capacity is not provided as the value is location-specific and should only be determined through engagement with the IESO's regional planning group.

Peak demand reductions estimated to derive avoided transmission capacity costs should be adjusted to reflect distribution system losses.

5.2.1.3. Avoided Energy Benefits

Electricity distributors are to quantify the estimated value of avoided energy costs due to NWS adoption. The IESO recommends approximating avoided energy costs using the most current forecasted marginal energy costs, available on the IESO website. This can support electricity distributors in performing a pre-assessment to determine if there are applicable energy system benefits. If it is determined that there are potential avoided energy benefits, electricity distributors are encouraged to validate and refine their estimated avoided energy system cost through the regional planning process or engagement with the IESO.

Energy savings estimated to derive avoided energy cost values should be adjusted to reflect distribution and transmission system losses.

Where implementation of an NWS will result in a net increase in energy consumption (e.g., such as in the case of efficiency losses from storage), these should be characterized as a negative energy avoided cost benefit.

5.2.1.4. Avoided Generation Capacity Benefits

Electricity distributors are to quantify, as a part of the EST cost-effectiveness test, the estimated benefit of NWS adoption due to avoided generation capacity needs. To perform the pre-assessment, the electricity distributor may reference the most recent Marginal Energy and Capacity Costs made available through the IESO's Annual Planning Outlook (APO) on the IESO website. Generic values from the IESO APO are only valid if the proposed DER behaves in a manner consistent with the APO's avoided cost modeling. For the system capacity avoided costs to be applicable, the DER must inject energy or reduce demand during the summer/winter peak demand conditions.

If it is determined that there are potential avoided generation capacity benefits, electricity distributors are encouraged to validate with the IESO. Coincident peak demand reductions estimated to derive generation capacity values should be adjusted to reflect distribution and transmission system losses.

5.2.1.5. Reliability (Net Avoided Interruption Costs)

Electricity distributors are permitted to identify any anticipated reduction to net avoided outage costs to customers from NWS implementation.

In identifying any such benefits, electricity distributors should be careful to distinguish between the reliability benefits that accrue to the electricity distributors' customers, and any reliability benefits that accrue to customers that are not customers of the electricity distributor.

Refer to section 4.5.1.2 for direction on how to characterize reliability benefits.

5.2.1.6. Resilience (Net Avoided Interruption Costs)

Electricity distributors are permitted to identify any anticipated improvement in energy system resilience from NWS implementation.

In identifying any such benefits, electricity distributors should be careful to distinguish between the resilience benefits that accrue to the electricity distributors customers, and any resilience benefits that accrue to customers that are not customers of the electricity distributor.

Refer to section 5.1.1.2 for direction on how to characterize resilience benefits.

5.2.1.7. Innovation and Market Transformation

Electricity distributors are permitted to identify any anticipated benefits that the NWS implementation may provide for market development or in supporting innovation that will result in lower cost service in the longer term.

In identifying any such benefits, electricity distributors should be careful to distinguish between the innovation and market transformation benefits that accrue to the electricity distributors customers, and any innovation and market transformation benefits that accrue to customers that are not customers of the electricity distributor.

Refer to section 5.1.1.4 for additional information related to this parameter.

5.2.1.8. Planning Value

Electricity distributors are permitted to identify any anticipated benefits that the NWS implementation may provide in terms of its planning or option value. Refer to section 5.1.1.5 for direction on how to characterize planning value benefits.

Electricity distributors should be careful to distinguish between the planning value benefits that accrue to the electricity distributor’s customers, and planning value benefits that accrue to others that are not customers of the electricity distributor.

5.2.2. Energy System Costs

This section describes each of the cost categories identified for consideration in the EST, either as quantitative costs included in the EST cost-effectiveness test, or as qualitative considerations.

5.2.2.1. Distribution Service Test Costs

The customers of the implementing electricity distributor are a sub-set of the larger group of provincial energy system customers. In most cases it is therefore appropriate to include in the EST all the costs also included in the DST.

5.2.2.2. NWS Acquisition Costs

Electricity distributors are to quantify, as a part of the EST cost-effectiveness test, estimated costs (beyond those considered as part of the DST) of acquiring the NWS.

Performance payments for curtailing at times of coincident energy system peak (provided curtailment at those times is not intended to also meet distribution needs) should be considered as part of the EST, but not the DST.

5.2.2.3. NWS OM&A Costs

Electricity distributors are to quantify, as a part of the EST cost-effectiveness test, the estimated costs of operating and maintaining the NWS under consideration as part of the BCA, as well as incremental administrative costs, including the costs of EM&V.

Incremental NWS OM&A costs associated with NWS's energy system benefits, beyond those to provide distribution service benefits should be noted.

5.2.2.4. Energy System Ancillary Costs

Electricity distributors are to identify any anticipated impact on energy system ancillary service costs.

Incremental NWS ancillary service costs associated with the NWS, beyond those imposed on the distribution system should be noted.

5.2.2.5. Risks (Energy System)

Electricity distributors are to identify the key risks that may impact the net benefits estimated as part of the cost-effectiveness test or the qualitative BCA considerations.

Incremental risks associated with the NWS, beyond those related to its performance for meeting distribution service needs should be noted.

6. FILING REQUIREMENTS

Electricity distributors are to document their proposals for NWS with the same level of rigour and depth as that provided for traditional poles-and-wires solutions when justifying the capital expenditure as part of a DSP or an ICM.

The level of detail in filings to the OEB should be consistent with the expectations outlined in Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications[34] for material investments included in the electricity distributor's DSP.[35] Electricity distributors are expected to include a level of detail in their proposals proportional to the costs and benefits of the project or program under consideration.

As per the NWS Guidelines, electricity distributors should explain the proposed NWS in the context of their DSP, including providing details on the system need that is being addressed, the infrastructure investments that are being avoided or deferred because of the NWS, and the prioritization of the proposed NWS relative to other system investments in the DSP.

6.1. Filing Format / Template

Electricity distributors are to submit filings on their proposed NWS using a similar format to that used by the distributor for justifying capital expenditures within the DSP. In all cases where a BCA was conducted (regardless of whether an NWS was ultimately selected), the following are to be specified:

- **Need.** A narrative description of system needs and the associated context. This should specify whether the need is discretionary or non-discretionary, the timing of the need, the main driver of the need, and any uncertainties.

- **Alternatives Considered.** Specification of the reference scenario and the alternatives under consideration. The reference scenario for non-discretionary needs will typically be the traditional poles-and-wires solution as this is what would be deployed under business-as-usual practices to ensure the reliability and continuity of customers' distribution service. The reference scenario for discretionary needs may be that no action is undertaken.

- **Cost-Effectiveness Test.** This section should include a summary of the sources and methods used to estimate the quantitative benefits and costs included in the tests, as well as a summary table of the impacts themselves and a discussion of any key areas of uncertainty related to these values. It is expected that a Letter of Comment from the IESO will be included for the EST. As noted above, the IESO

[34] Ontario Energy Board, *Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications*, December 2022

[35] Electricity distributors are required to document the rationale for why an NWS was deemed to not be a viable solution for a given system need, if such a scenario arises.

Letter of Comment is completed following the completion of the electricity distributor consultation with the IESO.

- **Other BCA Considerations.** A summary of the qualitative considerations or any additional supporting evidence for the preferred alternative.

- **Risk Mitigation.** Identification of monitoring, mitigation, and management strategies to address risks identified as BCA considerations.

- **Outcome.** A short, formal, confirmation of the alternative selected, and the essential specifications of that alternative.

6.2. Data Output Requirements

The BCA Framework is accompanied by an Excel-based quantitative output template. The use of this template is mandatory and is the minimum filing requirement of the BCA Framework. Electricity distributors may supplement the template with additional documentation, as they deem necessary.

The output template requires the electricity distributor to provide both the net present value of each impact considered in the BCA as well as the upstream quantifiable outcome driving that impact, where relevant.