ONTARIO ENERGY BOARD

Draft Benefit-Cost Analysis Framework for Addressing Electricity System Needs

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Ontario

Ontario Energy Board

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1. INTRODUCTION

The Benefit-Cost Analysis (BCA) Framework is an OEB policy document that outlines the methodology that electricity distributors are to employ when assessing the economic feasibility of non-wires solutions (NWS) to address defined electricity system needs. The BCA Framework is an outcome of the Framework for Energy Innovation (FEI) consultation, which was initiated to clarify the regulatory treatment of innovative and cost-effective solutions including NWSs and facilitate their adoption in ways that enhance value for customers.

This version of the Framework is Phase 1 in the OEB's BCA Framework development process. In this version, the focus is primarily on the distribution service BCA and its associated cost-effectiveness test for quantified impacts (the Distribution Service Test or DST). This Framework does address the current optional energy system BCA and its associated cost-effectiveness test (the Energy System Test[1] or EST) that electricity distributors may include with its BCA, but the OEB may expand on the direction provided for this form of BCA in a later Phase 2.

1.1. Background

The FEI consultation included the creation of an FEI Working Group (FEIWG) to provide advice to the OEB. In *Setting a Path Forward for DER Integration*[2] ("the FEI Report") the OEB concluded that it would launch a new initiative to develop a BCA Framework, including developing guidance on methodologies and standard inputs, and providing a template for filing BCAs.

1.2. Context for Use

The use of NWSs by distribution utilities is considered an element of Conservation and Demand Management (CDM). This Framework provides direction to electricity distributors on the development of the BCA required to accompany any application to deploy an NWS. It is the role of the OEB to facilitate the implementation of the best solutions to meet system needs.

The overall BCA is to follow the required structure provided in Section 6. Each BCA must include a distribution service BCA, which consists of a

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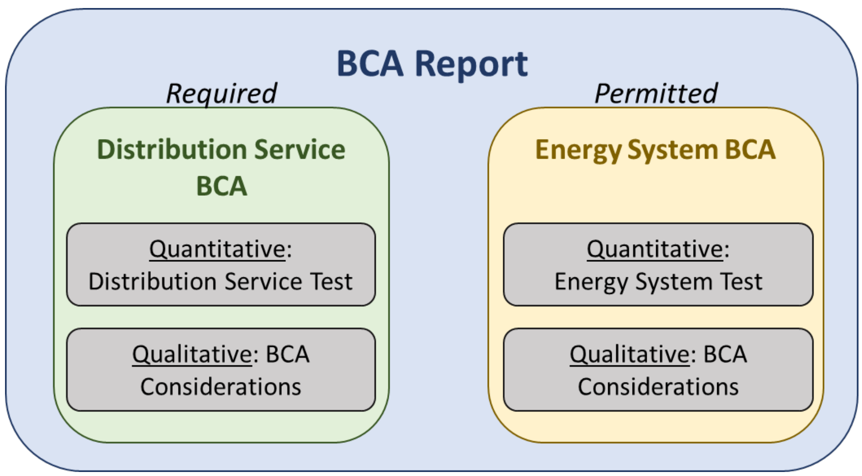
[1] Reference to the energy system within the BCA Framework is intended as a reference to the electricity system only at this time. As stated in the FEI Report, the OEB considers "energy system impacts" to include impacts on both the natural gas and electricity systems, however, more work is underway on how impacts related to the natural gas system could be incorporated in the future.

[2] Ontario Energy Board, *Framework for Energy Innovation: Setting a Path Forward for DER Integration*, January 2023
Available at the FEI consultation page:
https://engagewithus.oeb.ca/fei/news_feed/oeb-receives-the-fei-working-group-report

mandatory Distribution System Test (DST) and consideration of other qualitative distribution-level factors. Electricity distributors have the option of including an optional Energy System Test (EST) and consideration of other qualitative energy system factors. Electricity distributors may use the qualitative factors to support NWS proposals with lower DST or EST results. The DST considers the benefits and costs associated with an NWS from the perspective of an individual electricity distributor. Whereas the EST is a broader test, as it considers the benefits and costs associated with an NWS from the perspective of Ontario electricity system. More detailed definitions for the DST and EST can be found in Section 4.

Figure 1. Core Structure of a BCA



The remainder of this document 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 permitted and required impacts that they include.
4. **Benefits and Costs.** A detailed description of each of the types of impacts that may, or must, be included in the BCA, whether quantified as part of the cost-effectiveness test, or included as qualitative BCA considerations.
5. **Filing Requirements.** The required structure and content of the BCA.

2. PURPOSE AND USE

2.1. Purpose

The BCA Framework establishes a multi-test approach for use by rate-regulated electricity distributors in support of electricity distribution rate-setting applications to the OEB. The intent of the BCA Framework is to encourage the development of solutions that are in the best interests of both an electricity distributor's customers and Ontario's energy customers more broadly and to help level the playing field between NWS and traditional poles-and-wires infrastructure solutions to meet an electricity system need. As stated in the FEI Report, it is not the role of the OEB to increase or accelerate NWS adoption, or to choose one technology solution over another.

The BCA Framework includes guidance on methodologies, defines standard inputs and assumptions where possible, and provides a template to standardize project-specific BCAs across electricity distributors. Where possible, the BCA Framework aligns with other economic evaluations already in use for other purposes in the electricity sector in Ontario. The impacts considered have been defined to allow for use of the BCA Framework in distribution system planning and potentially other integrated planning processes (i.e., regional planning), where possible.

2.2. Criteria for Use

Consideration of NWSs in Addressing System Needs

The Conservation and Demand Management (CDM) Guidelines require electricity distributors to make reasonable efforts to incorporate consideration of CDM activities into their distribution system planning process. This is accomplished by considering whether distribution rate-funded CDM is the preferred approach to meeting a system need, in lieu of traditional infrastructure. As defined in the CDM Guidelines, CDM activities encompass all solutions that could be considered non-wires solutions.[3]

The BCA Framework establishes a new requirement that distributors shall document their consideration of NWSs when making material investment decisions as part of distribution system planning,[4] excluding general plant

[3] The OEB intends to convert the existing CDM Guidelines into Consolidated Guidance on NWSs. Some of the content in the "Purpose and Use" section of this draft BCA Handbook may be moved to the Consolidated Guidance on NWSs; however, the proposed approach is presented here to allow for stakeholder feedback on these proposals.

[4] As defined using the materiality thresholds in Chapter 2 of the *Filing Requirements for Electricity Distribution Rate Applications*.

investments. This does not mean that a BCA will be required in all cases; rather 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 binary screening criteria and technical evaluation stage used in Enbridge Gas's Integrated Resource Planning Framework[5] may be useful guides as to pre-assessment considerations relevant to the consideration of NWSs. Currently, the OEB is not establishing a mandatory format or requirements for the pre-assessment stage. It is expected that the degree of consideration of NWSs will vary depending on the system need, as some system needs may be clearly unsuitable for NWSs. Electricity distributors must provide rationale for all material infrastructure investment decisions where NWSs were not considered and/or those situations where NWSs were considered, but a BCA analysis was not conducted due to a pre-assessment finding.

Should the pre-assessment conclude that an NWS is a viable approach to meeting an identified need, a distributor should proceed with completing a BCA and documenting the results, to assess its economic feasibility.

When a BCA is Required

The BCA Framework is provided to support the evaluation of the economic feasibility (i.e., benefits exceed costs) of NWSs and provide a structured approach to enable electricity distributors to seek ratepayer funding to enable prudent investment in NWSs. 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 independent document within its filing or may include it as part of the project business case filed with the OEB. The BCA Framework will assist the electricity distributor and the OEB in determining whether an NWS, a traditional poles-and-wires infrastructure solution, or a combination of an NWS and traditional infrastructure solution is the preferred approach (i.e., the solution that provides the greatest net benefit) to meeting a system need, hence symmetrical treatment and application of the BCA Framework to traditional poles-and-wire and NWS solutions is required. The BCA Framework is required when the projected cost of the proposed solution to an electricity system need (either NWS or traditional infrastructure) exceeds the materiality threshold of a given

[5] Sections 5.2 and 5.3

electricity distributor. For proposed investments with projected costs less than the materiality threshold, electricity distributors may use the BCA Framework at their discretion.[6]

2.3. Interpreting BCA Outcomes

The DST is the mandatory test that must be employed by electricity distributors as part of the BCA Framework. The costs and benefits used for the calculation of the DST will be the primary consideration for assessing rate funding of an NWS. Proposed NWSs 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 would be considered to have a passing score on the DST. Only these NWSs would be included in applications for ratepayer funding to the OEB, except as noted below.

Electricity distributors have the option of employing the EST in addition to the DST to evaluate potential NWSs. 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 found to be marginally[7] non-cost-effective when applying the DST is still the preferred option to meet a system need.[8] The OEB will consider approving such proposals when there are compelling qualitative impacts that support the deployment of the specific NWS and/or the EST provides further justification as to the feasibility of a given NWS.

2.4. 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 applications, in conjunction with supporting Distribution System Plans. 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 CDM Guidelines, the OEB will also consider applications for CDM activities/NWSs outside of rebasing or ICM applications, if necessary. In such cases, the BCA Framework must also be utilized to support these applications.

The BCA Framework is effective for all electricity rate applications seeking approval for the 2026 rate year and onward. Rate applications filed by electricity distributors starting with the 2026 rate year (applications filed in

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[6] As defined using the materiality thresholds in Chapter 2 of the *Filing Requirements for Electricity Distribution Rate Applications*, page 6.

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

[8] Or conversely, that a traditional infrastructure solution is still preferred, despite a passing BCA score for an NWS.

2025) are expected to be consistent with the BCA Framework. If they are not, detailed explanations for any divergence are required, such as any unique circumstances of an electricity distributor, which will be taken into account. Electricity distributors have discretion in the application of the BCA Framework for rate applications seeking approval for the 2025 rate year.

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 take into account the unique circumstances of an electricity distributor's application.

For solutions addressing a distribution system need, the OEB's determinations on cost recovery arising from the use of the BCA Framework are expected to be limited to the ratepayers of the electricity distributor seeking approval for funding from the OEB. For solutions intended to address regional needs, the OEB would review the cost and associated rate impacts that would be borne by a rate-regulated electricity distributor net of any funding provided by other sources, as described in the CDM Guidelines.[9] The BCA Framework is not intended to provide a mechanism for an electricity distributor to recover costs from customers other than the electricity distributor's customers. The cost allocation that an electricity distributor proposes as part of its rate application may not necessarily be linked to the costs considered in a BCA cost effectiveness test.

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 must be completed and filed with the OEB for any proposed NWS. The templates are deemed the minimum informational requirements 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.

Currently, the BCA Framework is a standalone OEB policy document. It may however, be incorporated into other OEB policy documents (e.g., the OEB's Filing Requirements for Electricity Distribution Rate Applications, Conservation and Demand Management Guidelines for Electricity Distributors[10]) at a future date. The BCA Framework may be updated in the future as needed to account for future developments.

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[9] Section 4.3 of the December 20, 2021 CDM Guidelines

[10] EB-2021-0106, Conservation and Demand Management Guidelines for Electricity Distributors, December 20, 2021

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 must complete a BCA. BCAs are to be prepared for each specific system need and are not to be applied on a system-wide basis. This may be provided as a standalone document that accompanies an application, or be embedded directly in an application or utility distribution system plan (DSP).

The BCA's concluding outcome is informed by two sets of outputs; the cost-effectiveness test (or tests) which provides a quantitative assessment of the proposed NWS's net benefits to customers, and the qualitative BCA considerations.

For system needs that proceed to a BCA, all electricity distributors are required to complete a distribution service BCA for which the quantitative cost-effectiveness test is the DST, and which addresses qualitative considerations specific to the distribution service perspective.

Utilities may also, but are not required to, develop an energy system BCA. The quantitative cost-effectiveness test for this BCA is the EST. Energy system BCAs must, in addition to the cost-effectiveness test, address any qualitative considerations specific to the energy system perspective.

Additional specifics on these two perspectives for assessing long-term customer net benefits are provided in Section 4, below.

Both perspectives for assessing net benefits are described in this Framework, though it is expected that the energy system BCA will continue to evolve as the OEB proceeds with Phase 2 of the development of its BCA Framework.

This section of the Framework is divided into two sections.

- The first section (3.1) focuses on what kinds of information the electricity distributor should include in its BCA.
- The second 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 Grid 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 Grid Need Being Served

Electricity distributors must include a description in the BCA of the grid need being served. The need being served will define the reference scenario and the potential value of an NWS.

An illustrative (but not comprehensive) list of grid needs for which NWSs are typically applied as NWSs include:

- **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 Solution: Dispatchable or non-dispatchable NWSs, may include energy efficiency, demand response, or distributed energy resources (DER) (storage or generation).

  Assessment of Value to Bulk Energy System: When distribution system peak conditions are predictable, many NWSs will be able to deliver value to the bulk energy system outside of distribution 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 Solution: Dispatchable NWSs, may include demand response or DERs (storage or generation).

  Assessment of Value to Bulk Energy System: If NWS capacity must be held in reserve for unpredictable scenarios on the distribution system, the value the NWS is able to deliver to the bulk energy system may be limited.

- **Circuits with Underperforming Reliability** – This need is typically associated with radial circuits that lack tie lines for redundancy and therefore face frequent outages. Here, the traditional investment may be to add a redundant tie line, and the NWS would be to employ a solutions that can provide backup power to maintain service until the cause of an outage is addressed.

Suitable NWS Solution: Dispatchable NWSs, DER (storage or generation).

Assessment of Value to Bulk Energy System: If NWS capacity must be held in reserve for unpredictable scenarios on the distribution system, the value the NWS is able to deliver to the bulk energy system may be limited.

3.1.2. Forward-Looking Uncertainty

Electricity distributors may utilize expected value calculations to account for uncertainty where loss functions are asymmetric. Expected-value calculations may also help electricity distributors more accurately capture the long-term benefits of NWSs in aggregate and so provide a better estimate of the value of a given NWS in particular.

Consider the case of a distribution asset approaching capacity, but at a relatively slow rate of growth – at forecast growth (for example) the NWS is expected to defer the poles-and-wires need by four years. If growth is higher than expected the benefit of the NWS might be eroded (fewer years of deferral), but if, in contrast, growth becomes flat (perhaps due to other exogenous factors and natural efficiency gains) the benefit of the NWS – which now allows for indefinite deferral of an expansion – is much greater. Also consider for example a battery NWS that as a result of greater utilization (cycling) degrades quicker than anticipated (fewer years of deferral).

Expected-value calculations may be based on sensitivity analyses or scenario reviews conducted as part of the BCA, on historical data, or documented outcomes from similar or analogous projects. Supporting evidence must be provided for any probability estimates used in expected-value calculations.

3.1.3. Difficult to Quantify and Qualitative Impacts

BCAs include both required and permitted quantitative impacts, which are to be included in the relevant cost-effectiveness test, and both required and permitted qualitative BCA considerations that must be addressed.

Qualitative considerations *can* meaningfully influence the outcome of a BCA. The use of NWSs is a relatively recent phenomenon in the utility sector, and the technologies and programs that can be used as NWSs 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[11]:

- **Provide Numerical Evidence.** Even if no robust estimate of monetary value sufficient to justify inclusion in the BCA test(s) as a quantitative impact is available, claims of value will be much stronger when they are supported by numerical evidence.[12]

Qualitative BCA considerations should be specifically tied to the impact categories specified for each type of BCA (distribution service and energy system), and should likewise be specifically tied to one or both of the BCAs based on consideration of the perspective of BCA.

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.

For example, if an NWS is proposed to defer a distribution service need for five years, but is anticipated to continue to provide energy system value for another 10 years following the end of the deferral period, the costs of maintaining the NWS in that period must be accounted for by the EST, and not by the DST.

For another example, consider market development benefits and costs. An electricity distributor's BCA may propose to exclude incremental evaluation measurement and verification (EM&V) costs from the BCA on the basis that this incremental EM&V is required only by the novelty of the NWS, and so it should be treated as a market development cost. The electricity distributor cannot then make a case in its qualitative BCA considerations that the project is an important one for moving the market forward and spurring innovation, since it has explicitly excluded the costs it claims are associated with innovation from the analysis.

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[11] See Section C.3 of
National Energy Screening Project, National Standard Practice Handbook for Benefit-Cost Analysis of Distributed Energy Resources, August 2020
https://www.nationalenergyscreeningproject.org/national-standard-practice-Handbook/

[12] For example, a distributor may be able to estimate the decreased probability of an outage arising from implementation of an NWS, but not be able to assign a monetary value to this impact.

3.1.5. Incremental Analysis

In quantifying the benefits and costs of value streams, electricity distributor's BCAs should consider only impacts incremental to the reference scenario that captures the business-as-usual outcome. BCAs must articulate the reference scenario in enough detail such that it is evident that the impacts considered in the BCA are, in fact incremental.

Reference scenarios should align with business-as-usual electricity distributor practices. For 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 (i.e., the development of a poles-and-wires solution).

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

For example, if a utility provides customers who already have smart thermostats with incentives to enroll their smart thermostats into a demand response program to target a distribution system need, the utility could not claim (in the Energy System Test) any benefits from energy savings from the thermostats (outside of impacts associated with demand response events) since these would be delivered even absent the program that is providing the NWS.

3.2. How to Apply What is Included

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

3.2.1. Filing Format

The filing format is described in greater detail in Section 6.1, but is summarized immediately below to underline for electricity distributors the scope of the analysis expected as part of a BCA. BCA filings should include sections that address:

- Need
- Alternatives Considered
- Cost-Effectiveness Test
- Other BCA Considerations
- Outcome
- Risk Mitigation

Assumptions, narratives, and estimated values of impacts that have been quantified and included in the DST or EST should be documented in the “Cost Effectiveness Test” section, and more difficult to quantify impacts, or other important considerations informing the quantitative impacts (and the uncertainty associated with them) should be documented in the “Other BCA Considerations” section.

3.2.2. Net Present Value / Discounted Cash Flow Analysis

All value streams included in the cost-effectiveness tests must be evaluated on a net present value basis, in constant dollars. Consistent with the IESO’s guidance for the economic analysis of NWSs,[13] electricity distributors should 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.

Where input values used by an electricity distributor reflect a different inflation rate assumption, that assumption may be used to deflate the value stream to constant dollars, and the reasoning included in the BCA documentation.

The use of the social discount rate to capture the time-value of money 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 (respectively) for customers (see Sections 4.1 and 4.2). Electricity distributors weighted average cost of capital (WACC), among other factors, should be used in annualizing the revenue requirement associated with lump-

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[13] Independent Electricity System Operator, *Integrated Regional Resource Plans: Guide to Assessing Non-Wires Solutions*, May 26, 2023
Available at:
https://www.ieso.ca/en/Get-Involved/Regional-Planning/About-Regional-Planning/Planning-Information-and-Data

sum capital investments, but this revenue requirement is then discounted at the societal 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 value stream included in the cost-effectiveness tests.

3.2.3. Discretionary vs. Non-Discretionary System Needs

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

Traditional non-NWS investments to meet discretionary needs would typically require justification that the expected benefits of the project will outweigh its costs, although this may not have been in the form of a quantitative BCA. An investment for a system need is discretionary only when there is a reference scenario in which not making *any* investment could be an acceptable option. A nuance of this definition that is expected to become more prominent as the market for NWSs transforms is that *the availability of some NWSs may change the reference scenario*. This is addressed further below.

If the reference scenario requires *some* investment, then the need is non-discretionary. For non-discretionary scenarios, there is no ‘do-nothing’ option.

<u>Discretionary Investments</u>

In situations in which 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 must select 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 net present value is determined to be the most economically viable or cost-effective solution. As discussed in section 2.3, this does not prevent a distributor from proposing a project that is not the most cost-effective solution, based on qualitative considerations.

<u>Non-Discretionary Investments</u>

A common use-case of NWSs, however, is for deferring non-discretionary capital investments. In such cases, the benefits of the NWS may be considered the avoided (or deferred) costs of the traditional poles-and-wires solution – i.e., the default reference scenario investment.

Since a BCA is not required 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 must be taken to ensure that all benefits and costs considered are truly incremental to the reference scenario.

<u>The Impact of NWS Options on Reference Scenarios</u>

NWSs are not perfect substitutes for poles and wires and just as there are some use-cases where using an NWS as a substitute for a poles and wires solution is neither feasible nor practical, there will be some use-cases where a poles and wires solution is impractical and only an NWS is suitable.

In these situations, NWSs change the reference scenario. Consider, for example, the challenge of ensuring reliability of supply to remote communities at the end of long radial lines. It may simply not be feasible to twin the line or otherwise use some form of poles and wires investment to provide a level of reliability to which customers are entitled. In such a case NWSs might become the reference scenario, and undertaking a BCA might be neither appropriate, nor necessary. However, in these situations the electricity distributor is still expected to provide the estimated cost of a potential traditional poles and wires option in its filing to the OEB to demonstrate that a BCA is not required.

3.2.4. Study Period

The study period – 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.

For example, 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 is fully depreciated (e.g., 40 years after the deferred need date). 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.

3.2.5. Transparency and Validation

Electricity distributors are expected to complete the filing template (see Section 6) with a level of detail proportional to the materiality of the costs being incurred and benefits being achieved, and consistent with the expectations outlined in Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications[14] for material investments included in the utilities' distribution service plan.

As with other aspects of rate applications, including capital funding requests for traditional poles-and-wires investments, the BCA information filed in support of proposed electricity distributor spending may be tested during a hearing. Electricity distributors should ensure that their analysis is transparent, based on robust data and reputable sources, and replicable by others with the same inputs.

3.2.6. Projects and Programs

Electricity distributors may be unable to consider NWSs for system needs that require a relatively rapid response. They may be able to consider system needs in aggregate well in advance, but the precise parameters of requirements are 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 as NWSs, that may be used to address multiple (but similar) needs, at different locations within the distribution system.

4. DISTRIBUTION SERVICE AND ENERGY SYSTEM BCAS

Electricity distributors must include a distribution service BCA in their filings, and may include an energy system BCA. For each BCA included, the electricity distributor must quantitatively assess the 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 NWSs. This section describes the purpose and perspective of each test, identifies the value streams (impacts) each one may (or must) include, and provides some context for evaluating the outcomes of testing. Note that lost revenues are not considered to be a cost or benefit in the DST or EST. This is consistent with guidance in the

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[14] Ontario Energy Board, *Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications*, December 2022
OEB-Filing-Reqs-Chapter-5-2023-Clean-20221215.pdf

NSPM[15] to separate cost-effectiveness analysis from rate impact analysis.

All applications submitted by electricity distributors for the use of NWSs must calculate (and present to the OEB) the benefits and costs prescribed by the DST. Electricity distributors may also elect to calculate the benefits and costs prescribed for the EST.

The OEB's BCA Framework will continue to evolve, and as part of the Phase 2 development electricity distributors may expect potentially significant changes to be applied to the methods and assumptions required for the EST. The DST is expected to remain as defined below through Phase 2. Both tests and their requirements are expected to evolve over time to accommodate new information, new technologies, and new NWS use-cases.

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 utility's customers. It does so by comparing the costs of distribution service (e.g., the cost to meet an identified need) to the value of the distribution service (e.g., improvements to reliability experienced by the utility's customers).

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.

A passing score on the DST is required, unless other qualitative benefits warrant proceeding with the NWS. A distributor would only pursue NWS options where distribution service costs decline or are justified by improvements to distribution service that is provided to customers. Consideration of changes to service costs must necessarily (given the life of most distribution assets) take a long-term perspective.

The DST must be completed as part of the BCA submitted by the electricity distributor with its application to use an NWSs.

Since the DST is tightly focused on the net value of an NWS for distribution service, it excludes some value streams.

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

- Required or permitted. An impact must be included in the BCA (either in the cost-effectiveness test or as a qualitative BCA consideration) if

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

the table indicates it is required.

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

All impacts that are required must be included in the BCA.

Quantitative impacts must be included in the DST, whereas qualitative impacts may be included in the BCA as considerations (see Section 6, Filing Requirements). Electricity distributors are permitted to provide quantitative estimated values for impacts listed as “qualitative” in the table below, and include these in the DST, if they have the means to do so. Electricity distributors are required to provide a quantitative estimated value in the DST for all impacts listed as “quantitative”.

For example, electricity distributors are required to include a qualitative description of risks to distribution service value in the BCA. An electricity distributor may choose to quantify some risks and include those in the DST but is not required to do so.

Table 1. DST Impact Categories

Impact	Required/ Permitted	Quantitative	Qualitative
BENEFITS			
Distribution Capacity (Deferral or Avoidance Benefit)	**Required**	ü	
Reliability (Net Avoided Outage Costs)	**Permitted**		ü
Resilience (Critical Load Benefits)	**Permitted**		ü
Innovation & Market Transformation	**Permitted**		ü
Planning Value	**Permitted**		ü
COSTS			
NWS Acquisition Cost	**Required**	ü	
NWS Operations, Maintenance, and Administrative (OM&A) Costs	**Required**	ü	
Distribution System Ancillary Services Costs	**Required**		ü
Risks (Distribution System)	**Required**		ü

4.2. Energy System Test

The EST evaluates the impacts to all customers in Ontario, favouring 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 to evaluate its viability 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 consumers.

The rationale for the test is to promote solutions that lower overall electricity costs for Ontarians and provide experience and insight that could help reduce barriers to innovative non-traditional solutions. 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 (e.g., economic development impacts).

Electricity distributors are not required to complete the EST as part of their BCA, but are encouraged to do so, particularly if they believe the NWS offers significant benefits beyond those of distribution service.

Most DST impacts should also be included in the EST as the customers taking distribution service from the given electricity distributor are also provincial customers.

Where an electricity distributor elects to perform the EST it must include all "required" impacts identified in Table 2, below and is expected to quantify those impacts identified as "quantitative" in that table in line with direction provided in the section above for the DST.

Electricity distributors are recommended to engage with and make use of information developed by the IESO as part of the IRRP process,[16] including using values for energy system benefits estimated by the IESO IRRP Technical Working Group. Where the timing of the IRRP process does not align with the electricity distributor's BCA needs, it may consider using electricity distributor-specific values it has derived itself (provided sufficient supporting detail is provided) or some of the sources suggested below to provide alternative values. The alternative data sources suggested below are subject to on-going update and evolution as part of the IESO's planning processes and therefore, the electricity distributor must first verify that they are appropriate for the intended use.

[16] Independent Electricity System Operator, IESO Regional Planning Information and Data Release Guideline, April 2023

Benefits estimated by the IESO IRRP Technical Working Group, if available and of recent vintage, should generally be used in preference to the alternative values specified below.

The EST is expected to continue to evolve as the BCA Framework is developed and the recommended sources of input data may be updated accordingly during the process. It is also important to emphasize that the cost allocation that an electricity distributor proposes as part of its rate application may not necessarily be linked to the costs considered in a BCA cost effectiveness test.

Table 2. EST Impact Categories

Impact	Required/ Permitted	Quantitative	Qualitative
BENEFITS			
DST Benefits	**Required**	ü	
Transmission Capacity	**Permitted**	ü	
Avoided Energy Costs	**Required**	ü	
Avoided Generation Capacity Costs	**Required**	ü	
Reliability (Net Avoided Outage Costs)	**Permitted**		ü
Resilience (Critical Load Benefits)	**Permitted**		ü
Planning Value	**Permitted**		ü
Innovation & Market Transformation	**Permitted**		ü
COSTS			
DST Costs	**Required**	ü	
NWS Acquisition Cost (incremental to DST costs)	**Required**	ü	
NWS (OM&A) Costs (incremental to DST costs)	**Required**	ü	
Energy System Ancillary Costs	**Required**		ü
Risks (Energy System)	**Required**		ü

5. BENEFITS AND COSTS

This section of the Framework is divided into two sections. The first addresses the benefits and costs considered by the distribution service BCA, and the second addresses the benefits and costs considered by the energy system BCA.

Where a benefit or cost is a series of annual values, these must be deflated to the dollar year of the 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 BCA Benefits and Costs

This section describes the benefits and costs considered for the distribution service BCA.

There is not, at present, a centrally defined set of generic values that electricity distributors may use formulaically for conducting the DST. Electricity distributors may use the methods recommended below to estimate the values required for the test. Electricity distributors may also propose alternative methods for estimating these values but must be prepared to justify their choices within the context of perspective and goals of the DST, and the general considerations identified in Section 2.1. The validity of the methods used by electricity distributors for estimating DST benefits and costs can be assessed as needed on a case-by-case basis in rate applications.

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 3. 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 as a result of the adoption of the NWS	This is the primary target benefit of NWS projects and must be included in all related BCAs. 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 Outage Costs)	Accounts for customer outage costs due to a reduction in frequency and duration of outages, primarily associated with the value of lost load	For many NWSs, this benefit will not be applicable. For NWSs such as energy storage and dispatchable DG with islanding capabilities, this benefit may be applicable if the NWS enables customers to operate in islanded mode while the grid outage is being addressed. In rare cases, it may be possible that the NWS is used in a manner that would prevent outages 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.

Impact	Description	Considerations for Applicability
Resilience (Critical Load Benefits)	Accounts for value of serving critical loads during prolonged system outages	The Reliability impact above is typically associated with benefits of avoiding routine outages. If the NWS is capable of providing backup power for prolonged outages, for example multi-day outages associated with major storms, then there may be additional resiliency benefits, particularly if the loads served provide critical community services (e.g., emergency services, hospitals, fueling stations, grocery stores, shelters, etc.). The value of resilience is often difficult to quantify and highly dependent upon the specific loads being served.
Innovation & Market Transformation	Accounts for potential future benefits resulting from broader program or market development that is supported by the proposed investment (e.g., pilot project)	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 O&M savings from investments to improve customer service, or O&M 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	NWSs often provide option value that can help electricity distributors to manage costs and uncertainty, particularly uncertainty related to load growth. Deferral of investments will result in greater certainty of the scope of the need, and so a more efficient allocation of limited electricity distributor resources.
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 NWSs associated with the NWS solution, and the incremental distribution equipment required to be able to safely interconnect the NWS.
NWS Operations, Maintenance, and Administrative (OM&A) Costs	Costs to manage and maintain the NWS project or program. This includes any distribution system maintenance costs specific to the operation of the NWS.	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 • 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 the NWS could require the electricity distributor to make investments to manage power flow issues. For example, deploying distributed solar as an NWS may require 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.)

Impact	Description	Considerations for Applicability
Risks (Distribution System)	Accounts for uncertainty which may present schedule, cost, or performance risk	For NWSs, this consideration may be necessary to include as the downside counterpart to the upside Planning Value. For example, when accounting for potential increased benefits resulting from deferral that may be longer than planned, it is also important to account for potential decreased benefits from deferral that may be shorter than planned.

5.1.1. Distribution Service Benefits

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

5.1.1.1. Distribution Capacity (Deferral or Avoidance Benefit)

Electricity distributors are required 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 – of NWSs 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 (e.g., deferral of a transformer station).

- **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 (e.g., managed EV charging to defer load transfers).

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 NPV values 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.

Parameter	Definition	Source	Note
$NPVCoSreference_{\,y=}$	Is the net present value of the cost of service of the traditional solution in the year in which the analysis is being completed ($y = p$) for a solution installed at the reference scenario need date ($y = needDate$).	Calculated	The value should be expressed in constant dollars of the year in which the analysis is being completed.
$NPVCoSreference_{\,y=}$	Is the net present value of the cost of service of the traditional solution in the year in which the analysis is being completed ($y = p$) for a solution installed at the deferred need date ($y = needDate$).	Calculated	If the traditional solution is being avoided altogether this value may be zero.

Parameter	Definition	Source	Note
$RevRequirementRef_y$	Is the revenue requirement derived from the capital and O&M costs of the traditional solution, deployed at the reference need date, 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 requirements for calculating revenue requirements in the OEB's Cost of Service Filing Requirements.[17] Simplifying assumptions should be documented by the electricity distributor in its BCA. Annual O&M costs may be included in this value.
$RevRequirementDef_y$	Is the revenue requirement derived from the capital and O&M 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[18]	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 in their BCA what simplifying assumptions have been applied and should be prepared to provide their work papers when requested.

This approach is most suitable when benefits are tied to the deferral or avoidance of a specific need – for example, the deferral of a transformer station upgrade. Because of the specificity of this approach, estimated NWS benefits derived using Cost of Service methods are expected to always be higher than those estimated using the marginal capacity value approach described below.

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

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

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 utility programs. However, the marginal distribution cost may be higher for constrained circuits in comparison to the system as a whole. The annual benefit value may be calculated according to Equation 2, which is further described in Table 4:

Equation 2. Avoided Distribution Capacity Infrastructure

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

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 the cost-effectiveness testing, the series of annual values estimated using the equation above, or one similar to it, must aggregated into a net present value in constant dollars of the year in which the analysis is being undertaken, using the inflation and social discount rates prescribed by the IESO in its Guide to Assessing NWAs.[19]

The other variables are defined Table 4, below.

Table 4. 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.

[19] Independent Electricity System Operator, *Integrated Regional Resource Plans; Guide to Assessing Non-Wires Alternatives*, May 2023
Available at:
https://www.ieso.ca/en/Get-Involved/Regional-Planning/About-Regional-Planning/Planning-Information-and-Data

Parameter	Definition	Source	Note
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 the distribution element's peak relative to the project's nameplate demand reduction.	Program-specific	For example, a nameplate demand reduction of 100 kW on the distribution feeder with a 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 (e.g., due to clouds) of a solar array which could limit its peak load reduction contribution on an element of the distribution system.

Electricity distributors are not required to exactly replicate the approach defined above. The critical inputs 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.

Consider, for example, an electricity distributor concerned with the impact of EV adoption on its costs. The electricity distributor has procured an EV adoption study, which has provided a probabilistic locational projection of EV adoption over the next 20 years. Electricity distributor system planners have used this information to develop a projection of the approximate magnitude of investment required 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.).

As another example, consider a utility program targeted at constrained portions of the network with expected deferral needs that are several years away (and therefore do not require near-term procurement of firm resources). If the average marginal distribution cost across the whole system is $50/kW-yr and the average annualized deferral value on constrained circuits is $500/kW-yr, then the marginal distribution cost for this program would be expected to fall somewhere between those two values. The average value for the system would underestimate deferral value given that constrained portions of the circuit should have a greater contribution to marginal distribution cost than portions of the network that are not expected to require upgrades in the foreseeable future. On the other hand, the average annualized deferral value on constrained circuits would likely be an overestimate, as not all NWS capacity in the program will directly contribute to successful deferral in a given year.

Assume in this example that marginal distribution cost on the program's eligible circuits is $150/kW-yr, which takes into account expected load growth, corresponding planned investments due to that load growth, the NWS capacity required to achieve deferral, and the likelihood that NWS resources in the program successfully contribute to deferral in a given year.

If the program is expecting energy efficiency (EE) resources with a total of 10 MW demand reduction capacity (*ΔPeakLoad*) and expects 6 MW of coincident peak reduction based upon typical demand reduction profiles (i.e., *DistCoincidentFactor* = 60%). Additionally, to be conservative, a derating factor (*DeratingFactor*) of 80% is applied based upon variability in load reduction. (Although these EE resources are not dispatchable and are therefore expected to be available, the peak impact during any given event may be lower than the expected average reduction.) Average distributed losses between the location of the need and the NWS are estimated to be 1% (*Loss%*). In this case, the annual benefit would be about $727k per year (10,000 / (1-0.99) x 80% x 60% x 150).

5.1.1.2. Reliability (Net Avoided Outage Costs)

Electricity distributors are permitted to identify, as a qualitative consideration, any anticipated reduction to net avoided outage costs to customers as a result of the NWS implementation.

Reliability is the ability of the distribution system and its components to withstand instability, uncontrolled events, cascading failures and the unanticipated loss of system components.

Care should be taken to ensure only those benefits appropriate to the DST are considered. For example, an electricity distributor that provides customers that own behind-the-meter storage with an availability payment in exchange for using some share of battery output during peak periods could not reasonably claim that the project or program is delivering any reliability benefits; in this case these would be host, and not distribution service, benefits.

Reliability benefits may be claimed as a qualitative consideration of the BCA when, for example, it can be reasonably claimed that the NWS will improve the electricity distributor's response to disturbances and faults on the distribution system. Consider a scenario in which a long, radial feeder is experiencing frequent outages. The traditional solution may be to add a tie line and fault isolation capabilities in order to continue serving portions of the feeder until the outage is resolved. The NWA may be to add a storage system to the feeder, along with fault isolation capabilities, to provide backup power to the feeder during an outage.

In articulating considerations of reliability benefits It is also important to consider the distribution of outage events, not just average outage statistics, when considering impacts. For example, while an average outage may last 2 hours, some outages may last 8+ hours. In the example above, the tie line may be able to mitigate long-duration outages, while the storage system may reduce the outage duration but not avoid the outage altogether.

Electricity distributors confident in their assessment of the reliability benefits and equipped with a robust estimate of the impact of the NWS on SAIFI[20] or some other metric for customer outages may apply estimated values of metric improvement to an estimate of the value of lost load to customers in the area affected. Values 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. For example, in some cases it might be appropriate to adapt values drawn from the U.S. Department of Energy's Interruption Cost Estimate (ICE) calculator[21] to develop an estimated value stream for inclusion in the cost-effectiveness test.

NWS can sometimes provide ancillary services that support distribution grid reliability. To include this benefit, the electricity distributor must demonstrate that there is a need and value for ancillary services which would need to be addressed regardless of the NWS. For example, if the storage is addressing issues from solar that is also part of the NWS, then it is not driving an avoided cost relative to the reference case (traditional solution). It may ultimately serve to lower the cost of the NWS because other solutions (e.g., capacitor banks) may not need to be deployed, but it does not generate a net benefit relative to reference case. If a feeder has existing or projected voltage issues which would be addressed by the electricity distributor regardless of the NWS, then one potential way to value the impact is as the avoided cost of

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[20] System Average Interruption Frequency Index

[21] U.S. Department of Energy, developed by the Lawrence Berkeley

the alternative technology (e.g., capacitor banks) that would be otherwise be deployed.

In some cases, the use of NWSs 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 (e.g., due to impacts on the accuracy of load forecasting, impacts on voltage control, etc.) These issues should be addressed either in the estimation of the distribution capacity value (see Section 5.1.1.1, above, where the deferred upgrade also provides reliability improvements) or else in the estimation of NWS OM&A costs, distribution system ancillary costs, or risks (see Sections 5.1.2.2 through 5.1.2.7).

5.1.1.3. Resilience (Critical Load Benefits)

Electricity distributors are permitted to identify, as a qualitative consideration, any anticipated improvement in distribution system resilience as a result of the NWS implementation.

Resilience in this context may be characterized as the state of distribution service capable of being provided by the electricity distributor in response to a major disruption, that is the robustness and recovery characteristics of distribution system infrastructure and operation.

As with reliability, care must be taken to ensure that any resilience improvements being considered are distribution service improvements, and not just host resilience improvements.

The value of resilience is difficult to quantify and highly dependent upon the specific loads being served. 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 outage events. To the extent that electricity distributors may be able to estimate the value of these impacts, it is important to clarify the approach and key assumptions used in estimating this value.

These 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, as a qualitative consideration, 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 qualitative benefits of innovation and market transformation identified in the BCA considerations must be benefits that specifically improve the value of distribution service to customers over time and so to be claimed must be part of a consistent narrative of anticipated electricity distributor development. It is insufficient, for example, to only claim that the proposed NWS implementation will help to accelerate the adoption of behind the meter storage 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, the case must then be made that (again, for example) accelerated adoption of behind the meter storage will reduce the capacity acquisition costs for future NWS deployments.

Claims of innovation benefits must 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). Electricity distributors requesting that costs be excluded from the cost-effectiveness test on the basis that such costs are associated with "leveling the playing field" (i.e., market development). 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, as a qualitative consideration, any anticipated benefits that the NWS implementation may provide in terms of its planning or option value.

Planning value refers to the option value in the planning process, which is derived by allowing the electricity distributor to "buy time" in which 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 for half a century.

Planning value captures some of the benefits an NWS can offer for addressing uncertainty similar to the ways in which risk (Section 5.1.2.4) capture the costs imposed by an NWS when considering uncertainty.

These benefits are likely to be very difficult to quantify as they are often likely to be tied to asymmetric outcomes of unknown (and so typically assumed to be symmetric) probability distributions. Electricity distributors may identify this value as a qualitative consideration within the BCA, or if the electricity distributor has confidence in its understanding of the key uncertainties, may elect to attempt to quantify these benefits.

Should the electricity distributor wish to attempt to quantify the benefits of planning value, it may wish to do so by considering probabilistic outcomes for deferral benefits. Take, for example, an instance in which the estimated deferral period for the NWA solution is 5 years based upon projected load growth at 2% per year. However, there may be a 25% probability that load grows at 1% or less, and deferral may therefore be 10 years or more. The electricity distributor may provide analysis to quantify this upside potential.

If doing so, the electricity distributor should also consider the downside risk (see Section 5.1.2.7 regarding Risks). For example, there may also be a 25% risk that load grows at 3% or more, and deferral may therefore be less 3 years or less.

In this case, there are relatively symmetric probabilities which cause asymmetric benefits that disproportionately offer more upside benefit (5 extra years of deferral) than downside risk (2 fewer years of deferral).

Because many value streams may be impacted other than just the deferral benefit, the electricity distributor may choose to quantify the NPV and BCA under multiple scenarios and providing a probabilistic weight to each scenario.

Because these benefits may be difficult to quantify, the electricity distributor may choose instead to provide a qualitative discussion of associated Planning Value.

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). This will also require the distributor to clarify which costs would be treated as capital and which costs treated as OM&A for ratemaking purposes,[22] 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 required to quantify, as a part of the DST cost-effectiveness test, the estimated costs of acquiring the NWS or NWSs under consideration as part of the BCA.

This category includes all the costs related to acquiring the NWS capacity necessary to supply the identified need *that impact customer distribution service costs.* Given the unique nature of each need, and the (growing) variety of available NWSs it is impossible to be comprehensive in this document, and identifying the appropriate costs for inclusion will require electricity distributor judgement, and careful consideration of:

a) **The goal of the test** – to identify NWS options where distribution service costs decline or are justified by improvements to distribution service with the understanding that cost impacts to the body of distribution customers are determined on a net present value basis.

b) **The symmetrical treatment of incremental costs and benefits**, and the principle (articulated in the FEI report) that "costs must follow benefits", i.e., that a cost is appropriate for inclusion only if it can be demonstrated that it is associated with the delivery of distribution service benefits included in the BCA (either quantitatively or qualitatively), 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 DR aggregators.
- **Incentive Costs.** Payments to DR participants or other individual third parties providing DR.
- **Equipment and Systems Costs.** Costs for procuring equipment (load control equipment, storage, etc.) and the systems (software, hardware, training) necessary to effectively dispatch NWSs at times of distribution system need.

This is not intended to be a comprehensive list. Acquisition costs should

[22] It is likely that capitalization would only be applicable to some aspects of distributor-owned NWSs, not third-party NWSs. The FEI Report notes that associated capital and OM&A costs for NWSs would be treated in the same manner as costs for other distribution activities.

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.

In assessing what costs to include in the BCA, electricity distributors must 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.)

For example, some control room upgrades may be necessary to ensure the operational visibility and control necessary to use NWSs. If such control room upgrades are anticipated to be required by the electricity distributor regardless of the outcome of the specific project considered by the BCA, then it may be appropriate for those costs to be excluded from the BCA. Alternatively, if acquisition of the NWS requires some acceleration of the implementation of otherwise planned upgrades, then it may be appropriate to include in the BCA, only the incremental cost of accelerating the upgrades, and not the total cost of doing so.

Electricity distributors must be careful to not overlook incremental acquisition costs and observe the principle of symmetric treatment. For example, if taxes and insurance are included in calculating the benefit of deferring the traditional investment, then taxes and insurance for the utility-owned storage system should also be included as incremental costs.

The OEB can 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 (goal of the test, symmetric treatment of incremental costs and benefits) and their adherence 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 Operations, Maintenance, and Administrative (OM&A) Costs

Electricity distributors are required to quantify, as a part of the DST cost-effectiveness test, the estimated costs of operating and maintaining the NWS or NWSs under consideration as part of the BCA, as well as incremental administrative costs, including the costs of evaluation, measurement and verification (EM&V).

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

As with acquisition costs, comprehensive categorization of all OM&A costs is impossible. Electricity distributors may support their choice to include OM&A costs on the basis of the two principles identified in Section 5.1.2.1 (goal of the test, symmetric treatment of incremental costs and benefits).

Electricity distributors must carefully consider what OM&A costs are truly incremental. For example, administering a DR program may require three full-time equivalent staff (FTEs) over the four-year program period, but if the traditional poles and wires were anticipated to require 1 FTE per year in-service then the cost-effectiveness test should consider only the cost of two FTEs (assuming an equivalent cost per-FTE, or adjusted as necessary to reflect differences in cost per-FTE).

EM&V is an essential component of NWS deployment (e.g., for settlement purposes for DR), but EM&V is generally more rigorous (and more costly) in early implementations of technologies and programs. In-depth impact and process evaluation of (for example) an EV managed charging program may include electricity distributor-specific research that will substantially improve the net benefits of future managed charging program; for example, what brands of Level 2 EVSE can be cost-effectively connected to a DR dispatch system?

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).

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

The OEB can 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 (goal of the test, symmetric treatment of incremental costs and benefits) 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 required to identify, as a qualitative consideration, any anticipated impact on distribution system ancillary services costs.

Distribution system ancillary services can include voltage regulation, harmonic control, frequency management, and reactive power management. Incremental ancillary services costs are anticipated to be associated principally with intermittent distributed generation, and are not, at present, anticipated to be a significant driver of net distribution service benefit, though this may change in the future.

Examples of NWSs that may be relevant here include solar and storage. If an NWS results in high penetration of solar on a circuit, it could create the potential for voltage or backflow issues. In this case, there may be an incremental cost required to invest in equipment and/or controls that mitigate these issues. The relevant costs would be for the equipment and/or controls, deployment of the technology, and potentially any incremental O&M costs for the technology. In this case, it's important to avoid duplication with Distribution O&M Costs (see Section 5.1.2.8).

In the case of energy storage, it may be possible that the storage system can provide distribution ancillary services (e.g., voltage/VAR control). Distribution system ancillary service benefits (if any) should be captured in the discussion or quantification of reliability benefits (see Section 5.1.1.2).

5.1.2.4. Risks (Distribution System)

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

Electricity distributors must, for each quantitative value stream (costs and benefits) included in the cost-effectiveness test 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 must, or may, be included in an energy system BCA.

Electricity distributors are not at present required to include an EST in their filings. The guidance provided on the energy system BCA and the EST cost-effectiveness test is likely to evolve as part of Phase 2 of the BCA Framework development.

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. Distribution customers are also energy system customers.

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 NWSs 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.

As noted above, the EST is expected to continue to evolve as the BCA Framework is developed and the recommended sources of input data may be updated accordingly during the process. Further, the cost allocation that an electricity distributor proposes as part of its rate application may not necessarily be linked to the costs considered in a BCA cost effectiveness test.

5.2.1. Energy System Benefits

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

Electricity distributors are recommended to engage with the IESO as part of the IRRP process, and to use energy system benefits estimated by the IESO IRRP Technical Working Group. Where the timing of the IRRP process does not align with the electricity distributor’s BCA needs, it may use electricity distributor-specific values it has derived itself (provided sufficient supporting detail is provided) or some of the sources recommended below to provide alternative values.

Benefits estimated by the IESO IRRP Technical Working Group, if available and of recent vintage, should generally be used in preference to the other values specified.

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. In most cases, it is therefore appropriate to include in the EST all the benefits also 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 EST cost-effectiveness test, the estimated benefit of NWS adoption due to reductions of peak demand imposed on upstream transmission assets.

Electricity distributors may use (in order of preference) transmission capacity benefits provided by the IESO through the IRRP process, electricity distributor-specific values that have been developed by the electricity distributor, or the estimated transmission capacity values provided in the recent DER potential study developed for the IESO.[23] Benefits estimated by the IESO IRRP Technical Working Group, if available and of recent vintage, should generally be used in preference to the other values specified.

If not using values from the IESO IRRP Technical Working Group, electricity distributors are encouraged to select the Business-As-Usual (BAU) values ($112.26/MW-day).

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

5.2.1.3. Avoided Energy Costs

Electricity distributors are required to quantify[24], as a part of the EST cost-effectiveness test, the estimated benefit of NWS adoption due to avoided energy costs.

Electricity distributors may use (in order of preference) avoided energy costs provided by the IESO through the IRRP process, or avoided energy costs by eight-part time of use (TOU) period provided in the IESO cost-effectiveness

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[23] Dunsky, prepared for the Independent Electricity System Operator, *Ontario's Distributed Energy Resources (DER) Potential Study – Volume II: Methodology & Assumptions*, September 2022, Table C-2
Available under the September 30, 2022 engagement update provided at:
https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/DER-Potential-Study

[24] Although this is a requirement of the energy system BCA, electricity distributors are not at this time required to complete an energy system BCA. If they elect to do so, however, these impacts must be included.

tool.[25] Benefits estimated by the IESO IRRP Technical Working Group, if available and of recent vintage, should generally be used in preference to the other values specified.

If not using values from the IESO IRRP Technical Working Group, energy savings by TOU period estimated to derive avoided energy cost values should be adjusted to reflect distribution and transmission system losses.

5.2.1.4. Avoided Generation Capacity Costs

Electricity distributors are required to quantify, as a part of the EST cost-effectiveness test, the estimated benefit of NWS adoption due to avoided generation capacity requirements.

Electricity distributors may use (in order of preference) generation capacity benefits provided by the IESO through the IRRP process, or generation capacity value of $144/MW-year provided by the IESO in its IRRP Guide for NWAs.[26] Benefits estimated by the IESO IRRP Technical Working Group, if available and of recent vintage, should generally be used in preference to the other values specified.

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 Outage Costs)

Electricity distributors are permitted to identify, as a qualitative consideration, any anticipated reduction to net avoided outage costs to customers as a result of the 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 Outage Costs)

Electricity distributors are permitted to identify, as a qualitative consideration, any anticipated improvement in energy system resilience as a result of the

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[25] The spreadsheet tool and IESO CDM cost effectiveness guide may both be obtained from: https://www.ieso.ca/en/Sector-Participants/Energy-Efficiency/Evaluation-Measurement-and-Verification

[26] Independent Electricity System Operator, *Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives*, May 2023
Available at:
https://www.ieso.ca/en/Get-Involved/Regional-Planning/About-Regional-Planning/Planning-Information-and-Data

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, as a qualitative consideration, 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.

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 requirements and guidelines regarding applicable considerations for this parameter.

5.2.1.8. Planning Value

Electricity distributors are permitted to identify, as a qualitative consideration, any anticipated benefits that the NWS implementation may provide in terms of its planning or option value.

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

Refer to section 5.1.1.5 for direction on how to characterize planning value benefits.

5.2.2. Energy System Costs

This section describes each of the cost categories identified for consideration in the distribution service BCA, either as quantitative costs included in the EST, or as qualitative BCA considerations.

Electricity distributors are recommended to engage with the IESO as part of the IRRP process and, in addition to the estimated value of the NWS benefits, request a review by the IESO of the estimated costs to help identify any incremental energy system costs (beyond those identified for the distribution service BCA).

Benefits estimated by the IESO IRRP Technical Working Group, if available and of recent vintage, should generally be used in preference to the other values specified.

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 required to quantify, as a part of the EST cost-effectiveness test, the estimated costs of acquiring the NWS or NWSs under consideration as part of the BCA.

Incremental NWS acquisition costs associated with the NWS's energy system benefits, beyond those required to provide distribution service benefits should be noted. For example, DR participants may receive performance as well as availability payments. Performance payments for curtailing at times of coincident energy system peak (provided curtailment at those times is not also required to 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 required to quantify, as a part of the EST cost-effectiveness test, the estimated costs of operating and maintaining the NWS or NWSs under consideration as part of the BCA, as well as incremental administrative costs, including the costs of evaluation, measurement and verification (EM&V).

Incremental NWS OM&A costs associated with NWS's energy system benefits, beyond those required to provide distribution service benefits should be noted. For example, incremental EM&V required to meet any provincial contractual obligations for the provision of coincident peak capacity, any administrative costs associated with participating in the provincial capacity market, etc.

5.2.2.4. Energy System Ancillary Costs

Electricity distributors are required to identify, as a qualitative consideration, any anticipated impact on energy system ancillary services costs.

Incremental NWS ancillary service costs associated with the NWS, beyond those imposed on the distribution system should be noted. For example, the imposition of any incremental upstream needs to manage power quality associated with NWSs.

5.2.2.5. Risks (Energy System)

Electricity distributors are required to identify, as a qualitative consideration, 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. For example, risks related to conflicting requirements for the NWS to deliver both distribution service and energy system benefits. This could arise in a situation in which the NWS is required to support distribution system and bulk energy system capacity requirements on the same day, but at different times. If the NWS can be exercised only for a limited number of hours per day, this risk jeopardizes either the energy system or the distribution service benefits of the NWS.

6. FILING REQUIREMENTS

Electricity distributors are expected to document their proposals for NWSs with the same level of rigour and depth provided for traditional poles-and-wires solutions when justifying the capital expenditure as part of a Distribution Service Plan or an Incremental Capital Module. The level of reporting detail should be consistent with the expectations outlined in Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications[27] for material investments included in the utilities' distribution service plan.[28]

As with other aspects of rate applications, including capital funding requests for traditional poles-and-wires investments, the BCA information filed in support of proposed distributor spending may be tested during a hearing. Electricity distributors should ensure that their analysis is transparent, based on robust data and reputable sources, and replicable by a third party provided with the same inputs.

As per the CDM Guidelines, electricity distributors should explain the proposed NWS in the context of the electricity distributor's DSP, including

[27] Ontario Energy Board, *Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications*, December 2022
OEB-Filing-Reqs-Chapter-5-2023-Clean-20221215.pdf

[28] As discussed in Section 2.4, a distributor's documentation of material investments where an NWS was not selected should also include the distributor's rationale for this decision.

providing details on the system need that is being addressed, the infrastructure investments that are being avoided or deferred as a result 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 required to submit filings on their proposed NWSs 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), it must specify the following:

- **Need.** A narrative description of system requirements 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 (e.g., around the need date).

- **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 required under business-as-usual conditions to ensure the reliability and continuity of customers' distribution service. The reference scenario for discretionary needs may be no action undertaken.

- **Cost-Effectiveness Test.** This section should include a summary of the sources and methods used to estimate the 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.

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

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

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

6.2. Data Output Requirements

The BCA Framework will be accompanied by an Excel-based quantitative output template. This template is expected to evolve over time, reflecting (for example) the Phase 2 updates of the BCA Framework.

The output template will require the electricity distributor to provide both the net present value of each impact considered in the BCA as well as – where relevant – the upstream quantifiable outcome driving that impact. For example, for the deferral of a non-discretionary poles-and-wires BCA, the electricity distributor will be required to provide both its estimate of the NPV of the distribution capacity benefit, but also the capacity enabled by the NWS in question.