BCA Handbook – Project Plan

Prepared for:

Ontario Energy Board

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Disclaimers

List of Acronyms

BCA – Benefit-Cost Analysis

DER – Distributed Energy Resource

DR – Demand Response

FEI – Framework for Energy Innovation

LDC – Local Distribution Company

NPV – Net Present Value

NWS – Non-Wires Solution[1]

OEB – Ontario Energy Board

[1] For the purposes of this project plan, a Non-Wires Solution (NWS) has the same meaning as a Non-Wires Alternative (NWA).

1. Introduction

Guidehouse has been engaged by the Ontario Energy Board (OEB) to develop a benefit-cost analysis (BCA) Handbook for addressing electricity system needs, including distributed energy resource (DER) solutions as non-wires solutions (NWSs), for the use of electricity distributors. This Handbook is an essential component of the OEB's under-development BCA Framework.

The development of a BCA Framework is an outcome of the Framework for Energy Innovation (FEI) consultation.[2] This consultation was undertaken to clarify the regulatory treatment of innovative and cost-effective DER solutions.

Advice to the OEB from the FEI consultation was provided by the FEI Working Group (FEIWG) of stakeholders. From this larger group, the BCA Subgroup was formed and tasked with providing recommendations to the FEIWG for an approach local distribution companies (LDCs) might use for evaluating the net benefits of using DERs to defer or avoid traditional distribution investments.

As summarized in the BCA Subgroup report[3], the Subgroup recommended that the OEB establish an initial BCA Framework for DERs. The January 2023 report from the FEI consultation[4] included in Section 5 ("*Benefit Cost Analysis Framework for DER Solutions as Non-Wires Alternatives*") a commitment from the OEB to develop a BCA Framework to reduce the complexity and effort of carrying out BCAs for DER solutions as NWSs in system planning. This Framework would include five components:

1. **Purpose and Use.** Identification for LDCs of when a BCA is required and the BCA's intended use.
2. **Information Requirements.** A list of the impacts that must (or may) be considered for assessment in the BCA.
3. **Cost-Effectiveness Test.** A description of how the BCA should be used to inform the selection of the solution to be deployed by the distributor.
4. **Standardized Methods.** A description of the methods, assumptions, and tools that may be used for carrying out assessments.
5. **Reporting Requirements.** The format to be used by LDCs for presenting BCAs.

These components are all addressed in the outline of the BCA Handbook provided in this Project Plan, with: "Purpose and Use" addressed in Section 4.2, "Information Requirements"

[2] Ontario Energy Board, ***Framework for Energy Innovation (FEI)***, accessed August 2023

[3] Ontario Energy Board, ***Framework for Energy Innovation; Report of the BCA Subgroup***, EB-2021-0118, June 8, 2022

[4] Ontario Energy Board, ***Framework for Energy Innovation: Setting a Path Forward for DER Integration****,* January 2023
Available at:

addressed in Section 4.3, “Cost-Effectiveness Test” addressed in Section 4.4, “Standardized Methods” addressed in Section 4.5, and “Reporting Requirements” addressed in Section 4.6.

As noted in the FEI report, the OEB is developing its Framework in a phased approach.

In this current, initial phase, the OEB is developing a BCA Handbook to provide LDCs with guidance for assessing and reporting out the net distribution service benefits of DERs employed as NWSs, with some high-level consideration of bulk electricity system impacts. A subsequent phase will expand the Framework’s focus and provide an updated Handbook with more detailed guidance for assessing the net benefits of DERs to the broader electricity system, and the province as a whole.

This Project Plan is the first deliverable of this project. Subsequent deliverables include a complete draft of the Phase 1 BCA Handbook, including three examples, and a webinar presenting the finalized Phase 1 Handbook to stakeholders.

This Project Plan provides reviewers with a list of the key documentation (including BCA Handbooks from other jurisdictions) as examples consulted by Guidehouse, a discussion of the key issues considered by OEB Staff and Guidehouse in the development of the Plan and the Handbook, and a detailed outline of the Handbook itself. Key issues considered as part of the development of this Handbook may be found in Section 3, but also – in considerable detail – in the BCA Handbook outline itself, in Section 4.3.

This BCA Handbook outline (Section 4) is the most essential part of the Plan and is intended as a very preliminary draft of the Handbook on which stakeholders can comment . Some sections of this outline are essentially a complete first draft of that section of the Handbook, most however, provide a summary of the anticipated content that the given section will include.

2. BCA Documentation in Ontario and Other Jurisdictions

In developing its draft BCA Handbook for Phase 1 of the OEB's BCA Framework development process, Guidehouse has reviewed and consulted many sources, both for direct examples of the content and structure of a BCA Handbook, but also for important context and detail related to the specific requirements of Ontario LDCs.

Table 1, below, identifies, in alphabetical order by organization name, the documents drawn from other jurisdictions. This includes direct examples of handbooks from other jurisdictions. Sources consulted that are Ontario-specific are presented in another table below.

In developing its BCA Handbook outline, Guidehouse has leaned most heavily on the NYSEG and PSEG LI BCA handbooks, discussed further below, as a template for Handbook structure. In addition, Guidehouse has made significant use of the guidance of the NSPM in its discussion of general methodological considerations.

Table 1. Other Jurisdiction Sources

Source Document	Jurisdiction	Citation
ConEd - Framework Pursue Pipeline Alternatives	New York (Gas)	Consolidated Edison, *Proposal for Use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure*, Case 19-G-0066, January 2020
NSPM for DERs	N/A (Generic)	National Energy Screening Project, National Standard Practice Handbook for Benefit-Cost Analysis of Distributed Energy Resources, August 2020
NYSEG BCA Handbook	New York	NYSEG, Benefit Cost Analysis Handbook / Version 3.0, June 2020
PSEG LI BCA Handbook	New York	See Appendix B, PDF page 178 of 242 PSEG Long Island prepared for Long Island Power Authority, *Utility 2.0 Long Range Plan & Energy Efficiency, Beneficial Electrification and Demand Response Plan*, July 2022
RAP Reference Report	N/A (Generic)	Shenot, J. and Prause, E., Shipley, J., Regulatory Assistance Project, Using Benefit-Cost Analysis to Improve Distribution System Investment Decisions – Reference Report, November 2022
Rhode Island BCA TRM	Rhode Island	Narragansett Electric Company d/b/a National Grid, National Grid's Technical Reference Handbook for the Benefit-Cost Analysis of Non-Wires Alternatives in Rhode Island, May 2021
Xcel Energy Cost-Benefit of NWAs	Colorado	ICF, prepared for Public Service Company of Colorado, Cost-Benefit Analysis of Non-Wires Alternatives, May 2022

Table 2, below, identifies, in alphabetical order by short-form source document name, the key Ontario-specific documents reviewed and consulted by Guidehouse in the development of the

BCA Handbook. The most important sources for the BCA Handbook outline cited below are the FEI Report and the BCA Subgroup Report.

Table 2. Ontario Sources and Key Considerations

Source Document	Citation
IESO CDM C-E Tool User Guide	Independent Electricity System Operator, *Conservation and Demand Management: Cost-Effectiveness Tool User Guide Version 9*, May 2022
IESO C-E Guide	Independent Electricity System Operator, *Cost Effectiveness Guide for Energy Efficiency*, May 16, 2022
IESO Guide to NWAs	Independent Electricity System Operator, *Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives*, May 26, 2023
IRPWG DCF+ Report	Ontario Energy Board, *Use of the Discounted Cash Flow-Plus Test in Integrated Resource Planning (IRP): Report of the IRP Technical Working Group*, May 2023
OEB BCA Subgroup Report	Ontario Energy Board, Report of the BCA Subgroup, June 2022.
OEB CDM Guidelines	Ontario Energy Board, *Conservation and Demand Management Guidelines for Electricity Distributors*, EB-2021-0106, December 2021
OEB DSP Filing Requirements	Ontario Energy Board, *Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications*, December 2022
OEB FEI Report (or "FEI Report")	Ontario Energy Board, *Framework for Energy Innovation: Setting a Path Forward for DER Integration*, January 2023
OEB IRP Decision & Order (Gas)	Ontario Energy Board, *Decision and Order EB-2020-0091 Enbridge Gas Inc. Integrated Resource Planning Proposal*, July 2021.

3. Key Considerations for the BCA Handbook

Development of the BCA Handbook outline presented in Section 4, below, has been guided by the outcomes of the FEI consultation for the content of that Handbook. This, in addition to input provided directly by OEB staff, and Guidehouse's understanding of the typical use-cases for DERs as NWSs has driven the selection of which impacts from the comprehensive list identified in the BCA Subgroup Report should be considered.

Finally, in developing Handbook outline materials, Guidehouse has carefully considered the structural challenges to the implementation of DERs as NWSs, and how recommendations from the FEI consultation should impact the BCA guidance provided in the Handbook.

3.1 Direction of the FEI Consultation & Integration Into the Existing BCA Ecosystem

The content and structure of the BCA Handbook are being developed in response to the recommendations provided to the OEB, documented in the FEI report[5], to provide guidance to LDCs on BCA methodologies, establishing standard inputs, and creating templates for LDCs to use in completing their BCAs.

The development of the OEB's BCA Framework will take place in Phases. This draft of the BCA Handbook is intended to support Phase 1 of that development. As such, it is focused on providing LDCs with the guidance and information required to conduct a BCA based around the Distribution Service Test (DST), within which the costs and benefits accruing to the implementing distributor's distribution service to customers will be the primary consideration for investment decisions.

In Phase 2, development will focus on enhancing the guidance provided to LDCs in the BCA Handbook on capturing impacts that apply outside the bounds of the LDC's service territory through the Energy System Test (EST). Though this test will be characterized in this first version of the BCA Handbook, it is not the primary focus of Phase 1, and so the guidance provided here should be regarded as transitional.

Because the perspective of this secondary test prioritizes the net benefits provided by the contemplated DER to the wider energy system, it is essential that the BCA methods and inputs (for the EST) align with those used by the IESO for assessing the system-level value of DERs. This is especially true where the system-level value of the DER is driven by the assumption that it can act as a regional as well as a purely local (distribution system) NWS.

A key consideration for this version of the Handbook and – especially – for Phase 2 of the framework development, is how to ensure the alignment of net benefits delivered by the EST with those that might later be provided by the IESO's IRRP Technical Working Group.[6] It is this group that is responsible for valuing NWS-type benefits provided by DERs to the bulk energy

[5] Ontario Energy Board, ***Framework for Energy Innovation: Setting a Path Forward for DER Integration***, January 2023, Page 22

[6] See Section 6 of Independent Electricity System Operator, ***Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives***, May 26, 2023

system, and any such values developed by the IESO will more accurately capture system level benefits than the generic benefits identified for the EST in this version of the BCA Handbook.

It is for this reason that the Phase 1 version of the BCA Handbook will recommend that, if possible within the LDC's other time constraints, the LDC begin by assessing the DST, then, if it wishes to quantify any NWS benefits the DER offers the wider energy system, engage with the IESO, likely through its IRRP process. Where the timing of the IRRP process does not align with LDC constraints, LDCs may develop values for the EST according to the guidance of the Phase 1 BCA Handbook (for which the outline is presented below). LDCs must recognize, however, that any subsequent valuation of benefits provided by the IESO will supersede those developed based on the values recommended by the BCA Handbook, provided these are received before it has submitted its BCA to the OEB (as part of an application). Where input values are not available from the IESO prior to the LDC's application, the application will be assessed on the best information available at the time of – and included in – the application.

3.2 Impacts Addressed by the Tests

The BCA Subgroup report set out a number of high-level impacts that are potentially material to a BCA, including but not limited to distribution service. Within each of these categories, the BCA Subgroup report identified specific impacts under each of the high-level categories noted above.

Below is a summary of the impacts considered by the DST and EST, as compared to the impact categories identified in the BCA Subgroup report.

Phase 1 of the BCA Handbook focuses on the DST. It is expected that the impact categories of the EST may change in Phase 2 of the Handbook development process.

The table below indicates which of the impact categories defined in the BCA Subgroup Report are applicable to the DST and EST. Their applicability to either test is categorized as follows:

(i) Required (R). These impacts must be included in the LDC's BCA

(ii) Permitted (P)These impacts may be included in the LDC's BCA, but are not required.

(iii) Excluded (E). These impacts may not be included in the LDC's BCA.

Impacts that are required or permitted to be included in the BCA may be either quantitative or qualitative in nature, depending on the data and information available to the LDC.

Table 3. DST and EST Impact Categories

Impact	Included in DST	Included in EST	Notes
Distribution Cost	R	R	
Distribution Capacity	R	R	
Distribution O&M	P	P	O&M and ancillary services impacts may be included within distribution cost/capacity impact category
Distribution Ancillary Services	P	P	

Impact	Included in DST	Included in EST	Notes
(Distribution Service) Risk	R	R	It is expected that in some cases risk impacts may be quantifiable (e.g., as expected values), risk impacts may in many cases be identified only qualitatively.
Host DER Costs	E	E	
Host DER Risk	E	E	
Host Customer Non-Energy Impacts	E	E	
Transmission Capacity	E	R	
Transmission Risk	E	R	It is expected that in some cases risk impacts may be quantifiable (e.g., as expected values), risk impacts may in many cases be identified only qualitatively.
Energy	E	R	System level impacts to commodity (energy and capacity) recommended for consideration within the EST
(Generation) Capacity	E	R	
Distribution System Losses	P	P	DST: Permitted only if Distribution loss rate is improved through NWS. EST: Capacity and energy savings should be scaled appropriately to account for losses.
Transmission System Losses	E	P	
(Bulk System/Resource) Risk	R	R	It is expected that in some cases risk impacts may be quantifiable (e.g., as expected values), risk impacts may in many cases be identified only qualitatively.
Market Price Effects	E	P	Most DERs are expected to be insufficiently large to impact market prices. In the long term, these could become more applicable as the size of NWSs increases

Impact	Included in DST	Included in EST	Notes
(Bulk System/Resource) Ancillary Services	P	P	Ancillary services impacts may be included within distribution cost/capacity impact category
Reliability	R/P	R/P	Where the impact is a cost, it is required to be included. Where it is a benefit, it may be included by the LDC.
Resilience	R/P	R/P	
Planning Value	P	P	
Innovation and Market Transformation	P	P	
Other Energy System Impacts	E	E	
Societal Impacts	E	E	

3.3 Addressing Challenges for LDCs

Significant challenges exist that handicap the development of DERs as NWSs to be able to truly compete with traditional poles-and-wires solutions on an equal footing.

The OEB's BCA Framework can, through the guidance it provides to LDCs, mitigate some of these challenges, but many will remain. This section identifies some of the challenges noted by OEB staff and considered as part of the BCA Handbook development. These challenges are highlighted in this Project Plan such that they might also be considered by all parties involved in the regulatory process of BCA review.

The OEB has previously expressed that its goal is to support the deployment of solutions that are optimal for customers, maximizing the value of their distribution service. The OEB's goal is *not* to promote DERs for their own sake or to prefer DERs to other solutions for providing distribution service.

The OEB's role is that of "*facilitating a level playing field*"[7] to allow DERs to compete as NWSs with traditional poles-and-wires solutions. The FEI Report and BCA Subgroup Report both document the challenges of leveling this playing field. The most significant of these challenges, from the perspective of delivering distribution service value to customers[8] are re-stated below.

What is required to level the playing field, and to enable DERs to compete as realistic alternatives on an equal footing to traditional poles-and-wires solutions?

[7] Ontario Energy Board, *Framework for Energy Innovation: Setting a Path Forward for DER Integration*, January 2023, Page 10

[8] A significant challenge to "leveling the playing field" relates to the preference for utilities for solutions that allow them to capitalize their costs. This is a challenge related to shareholder value, and not distribution service value. It is thus beyond the scope of the BCA Framework and so not addressed here.

- **Process Development.** LDCs have well-established processes for assessing, procuring, and implementing traditional poles-and-wires solutions that have historically been required to ensure the reliability and continuity of their distribution service. These are supported by decades of acquired human capital and progressively evolved workflows. Assessing, procuring, and implementing DERs – in the context of the prudent management of distribution service – cannot realistically be expected to perform at the same level of efficiency.

  The need for process development means that there is significantly greater operational uncertainty and risk associated with deploying DERs as NWSs than there is a traditional poles-and-wires solution.

- **Performance Development.** Poles-and-wires solutions are very costly, but very little uncertainty surrounds their performance and ability to meet system requirements. The use of DERs as NWSs for distribution needs is still a market in its very early stage of development, and though the performance of individual elements (e.g., residential A/C load control for DR) is generally well-understood, the performance of integrated solutions is not. What if the intra-daily timing of a need shifts due to EV charging – will the DER have capacity at 1am? What if the frequency of the need increases – can the DER be dispatched every day for a week if there's a major heat wave? Even if the DER can meet the need when called, are the controls sophisticated enough to call it at precisely the right times?

  The need for performance development means that there is significantly greater performance uncertainty and risk with deploying DERs as NWSs than there is a traditional poles-and-wires solution.

Regulatory Development. The BCA Handbook and its associated Framework will provide LDCs with guidance and greater certainty about the regulatory treatment of DERs as NWSs. As with any relatively novel process, however, many lessons will have to be learned by parties within the regulatory environment through application. These are all significant sectoral challenges that must be overcome to "*level the playing field*". Overcoming these challenges may be thought of as a fixed cost of a developing market or infant industry; potentially trivial in contrast to the long-term variable benefits offered by a market in which DERs compete unhindered with poles-and-wires, but significant in the short-term.

The pace of the development of the market for DERs as NWSs, and consequently the value that market can provide to distribution service, will inevitably be impacted by the degree to which these sectoral fixed costs are implicitly applied to early adopters. This is especially true in Ontario where there exist so many modestly-sized distribution utilities.

The BCA Framework can contribute to mitigating *some* of these challenges, and it is with consideration of how these challenges impact the OEB's facilitation of a level playing field that the BCA Handbook has been developed. These challenges are highlighted in this Project Plan such that they might also be considered by all parties involved in the regulatory process of BCA review.

4. BCA Handbook Outline

This section provides a detailed outline of the BCA Handbook and includes draft content of some of its key sections.

The BCA Handbook is expected to be a concise, practical, and actionable tool for LDCs to test the cost effectiveness of DER solutions as NWSs and traditional infrastructure solutions alike. The final product is expected to be approximately 30 pages, excluding examples.

The approximate length of each section will be:

1. **Introduction**: 1 – 2 pages
2. **Purpose and Use**: 2 – 4 pages
3. **General Methodological Considerations**: 11 pages
4. **Cost Effectiveness Tests**: 4 – 8 pages
5. **Benefits and Costs**: 8 – 16 pages
6. **Reporting Requirements**: 1 – 3 pages

The level of detail provided in this section of the Project Plan varies by sub-section. One section (Section 4.3, General Methodological Considerations) is essentially a complete preliminary draft of the Handbook section. The remainder provide a summary, or example(s), of intended content.

4.1 Introduction

The introduction of the BCA Handbook will provide a summary of:

- **Background.** A capsule history of the activities and work that led up to its development, including reference to the FEI *Report of the BCA Subgroup* and the FEI *Setting a Path Forward for DER Integration* report.

- **Purpose.** A summary of the need the BCA Handbook is fulfilling, and high-level direction as to its use (e.g., concise summary of key elements of Section 4.2 – Purpose and Use). Specifically, the BCA Handbook is intended to provide guidance to LDCs undertaking benefit-cost analyses to assess the cost-effectiveness of meeting a distribution service need with a DER – with a non-wires solution (NWS) - in order to defer or avoid a traditional poles-and-wires solution.

  The BCA Handbook is intended to supplement the evidentiary requirements of the CDM Guidelines by providing LDCs with more specific guidance and "*defining an approach to measuring the benefits of distributed energy resources relative to costs and assessing the value of distributed energy resources relative to traditional distribution investments.*" [9]

[9] See Section 3.2 of
Ontario Energy Board, ***Conservation Demand Management Guidelines for Electricity Distributors***, EB-2021-0106, December 2021

- **Future Development.** An acknowledgement of the evolving nature of DER NWS technologies and the associated policy landscape. The introduction will make clear that LDCs should expect a Phase 2 update to the Handbook. This Phase 2 will focus on broader energy system impacts and revisit the question of whether societal impacts should be included in the BCA Framework. It should be understood that the Energy System Test (and associated inputs) specified in this Handbook will be the focus of Phase 2, and LDCs should expect guidance on the use of this test and development of its inputs to evolve significantly.

4.2 Purpose and Use

The "Purpose and Use" section will be developed by OEB in the final BCA Framework.

The intent of this section is to identify and describe when a BCA is required and how that BCA should be used in the context of the OEB's regulatory activities.

More specifically, the "Purpose and Use" section will identify, define (or describe):

- **Criteria for Use.** This will define when LDCs are required to complete a BCA, including any pre-BCA assessments that are required or recommended (e.g., if a local need is large a poles-and-wires solution will be almost certainly more cost-effective). Pre-BCA assessment activities may be analogous to some of the assessment process steps defined in the OEB's Decision and Order[10] setting out Enbridge Gas Inc.'s IRP assessment process. In that process, an economic analysis (a BCA) is conducted only after:
    - *Identification of Constraints* through the demand forecast, up to 10 years in the future.[11]
    - *Binary Screening* for key criteria defining if a BCA is required (e.g., where the costs for a traditional solution for a pipeline replacement is less than $2 million, projects can be screened out, eliminating the need for a BCA).[12]
    - *Technical Evaluation* to assess whether a non-pipes solution is a viable alternative to a traditional infrastructure upgrade.

[10] Ontario Energy Board, *Decision and Order – Enbridge Gas Inc. – Integrated Resource Planning Proposal*, EB-2020-0091, July 22, 2021

[11] The IESO's Guide for NWAs (citation below) recommends screening out any constraints or system needs less than two years distant from present, noting that most NWSs require at least two years to implement, though such screening appears intended to be applied discretionarily.

See Section 3.3 of

Independent Electricity System Operator, ***Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives***, May 2023

[12] The NSPM notes that this is a consistent feature of NWS BCAs across jurisdictions – there is often a minimum cost threshold for project to be considered by NWS solutions – see Section 12 of that document. Guidehouse notes that the implicit reasoning for not considering NWSs below certain price floors appears to rest on the assumption of relatively high fixed costs (both real and opportunity costs) to utilities in assessing, developing and implementing NWSs. If, in future, processes and systems (such as those already in place for required "traditional" poles and wires investments) are developed by utilities and the regulator that reduce those fixed costs, cost floors as thresholds for DER assessment should be lowered.

This section will identify all currently envisioned precursor conditions that must be addressed by an LDC prior to undertaking a BCA according to the Handbook's guidelines.

- **Development & Submission Process.** Essential house-keeping direction for LDCs: this will describe how LDCs may submit BCAs as part of a rebasing application or as an application outside of rebasing, consistent with the CDM Guidelines.[13]

- **Interpreting BCA Outcomes and the Handbook Requirements.** LDCs must be provided with an indication of what is considered an acceptable outcome (or pass) of their BCA – e.g., a DST result of 1 or more for any LDC-proposed NWS, consistent with the OEB's policy priorities and the guidance of the Renewed Regulatory Framework. Some indication should also be provided of the OEB's expectations with respect to the prescriptiveness of the Handbook.

- **Regulatory Context.** The OEB intends to incorporate the use of BCAs developed by LDCs in accordance with the BCA Handbook guidance into OEB policy and guidance documents. This section should provide some initial guidance on the use of BCAs for DER solutions as NWSs as they relate to the filing requirements for Distribution System Plans[14], and for LDC CDM Guidelines.[15]

4.3 General Methodological Considerations

Any LDC proposing to use a DER as an NWS must, where material investment is required, complete an BCA. The primary, and compulsory, output of this analysis is benefit-cost ratio or set of net benefit values (benefits less costs) for competing alternatives calculated according to the requirements of the Distribution Service Test (DST).

Utilities may also, but are not required to, develop a benefit-cost ratio calculated according to the requirements of the Energy System Test (EST). Both testing approaches are described in the Handbook, though it is expected that the EST will continue to evolve as the OEB proceeds with Phase 2 of the development of its BCA Framework.

This section of the Handbook is divided into three sections. The first section focuses on inclusion considerations: how comprehensively must value streams be included? How to account for values not easily quantified? etc. The second section focuses on *how* value streams (once included) must generally be treated. The final section provides a structure to assist LDCs in understanding when and where these considerations apply, but describing how LDCs should develop and document the BCA narrative through identification of the system need, the applicable DER solution(s), and how that solution will be procured.

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[13] Ontario Energy Board, ***Conservation and Demand Management Guidelines for Electricity Distributors***, EB-2021-0106, December 20, 2021

[14] Ontario Energy Board, ***Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications – Chapter 5: Distribution System Plan***, December 15, 2022

[15] Ontario Energy Board, ***Conservation and Demand Management Guidelines for Electricity Distributors***, EB-2021-0106, December 20, 2021

4.3.1 What to Include

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

1. Description of Grid Need Being Served
2. Comprehensive Valuation of Benefit Streams Not Required
3. Forward-Looking Uncertainty
4. Difficult to Quantify Impacts / Qualitative Impacts
5. Symmetrical Treatment
6. Incremental Analysis

4.3.1.1 Description of Grid Need Being Served

LDCs must include a description in the BCA of the grid need being served. The need being served will define the possible DERs that could address it and the reference scenario. These in turn will define how impacts from the DER should be considered and valued. An illustrative (but not comprehensive) list of grid needs for which DERs are typically applied 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 a DER 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 DER Solution: Dispatchable or non-dispatchable DERs, may include energy efficiency, demand response, or distributed supply (storage or generation).

  Sources of Value: When distribution system peak conditions are predictable, many DERs 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 utility's ability to provide service in contingency scenarios.

  Suitable DER Solution: Dispatchable DERs, may include demand response or distributed supply (storage or generation).

  Sources of Value: If DER capacity must be held in reserve for unpredictable scenarios on the distribution system, the value the DER 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 DERs that can provide backup power to maintain service until the cause of an outage is addressed.

Suitable DER Solution: Dispatchable DERs, distributed supply (storage or generation).

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

4.3.1.2 Comprehensive Valuation of Benefit Streams Not Required

LDCs wishing to limit the administrative costs of completing the BCA are not required to comprehensively document or calculate all benefits that accrue to the DER being proposed as an NWS. If, for example, the LDC can demonstrate that the DER is unambiguously cost-effective while considering only (for example) the distribution capacity deferral benefits of a storage solution, it is not required to also estimate (again for example) any ancillary services benefits that that DER might provide.

LDCs must, however, document and include in the BCA all relevant and material DER costs, as defined in Section 4.5 below.

Only value streams quantified as part of the BCA can be used by LDCs in support of any utility incentive proposal subsequently submitted by the LDC to the OEB.[16]

4.3.1.3 Forward-Looking Uncertainty

LDCs may, but are not required to, adjust the estimated or projected values that drive benefits or costs to account for questions of uncertainty, provided such treatment is applied symmetrically. Such adjustments may include de-rating projected demand growth (e.g., when based on customer connection requests) or the use of expected-value calculations where loss functions are asymmetric.

For example, the probability of future demand being 15% higher or lower than projected may be similar (symmetric), but the consequences for the estimated value stream of the DER may *not* be symmetric. Calculating benefits on an expected-value basis in such situations can differentiate the benefits of low/no-regrets actions from much riskier proposals.

Expected-value calculations may also help LDCs more accurately capture the long-term benefits of DERs in aggregate and so provide a better estimate of the value of a given NWS. 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.

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[16] For more details of the incentive mechanisms available to LDCs for the use of third-party DERs as NWSs, please see:

Ontario Energy Board, ***Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives***, March 28, 2023

Expected-value calculations or proposed de-rating factors 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.

Forward-looking uncertainty may be applied for the purposes of conducting the BCA, however, utility incentives and the associated metrics will be based on observed performance and ex-post estimates of value.

If some quantification or discussion of project uncertainties forms a key component of the BCA, the utility must differentiate specifically between the types of uncertainty being considered. A non-comprehensive list of some of the typical sources of uncertainty that might impact the expected value of a DER (compared to a traditional poles and wires solution).

- Forecast Demand Magnitude Uncertainty. Faster than expected growth in demand can erode a DER's value for the deferral of capital investments, and slower than expected growth can significantly increase it.
- Forecast Demand Timing Uncertainty. The timing of peak demand is not typically a concern with a traditional poles and wires investment – the asset is sized to the demand, whether it occurs at 6pm or 1am. For a DER timing is a major consideration. Aggregated residential demand response from air conditioning curtailment (for example) may be sufficient to defer investment when the system peaks on a summer afternoon, but of no value if the loads served by the asset switch to become winter peaking.
- Delivery Uncertainty. Can the DER deliver the capacity anticipated when called upon to do so?
- Operational Uncertainty. Can the utility's control room dispatch the DER capacity when it is needed?

This list is intended only to be illustrative and not comprehensive.

LDCs should note that regulatory uncertainty (e.g., will a proposed utility incentive or cost for a project be approved or not?) is *not* appropriate for inclusion in any quantification of value for the purposes of developing a BCA.

4.3.1.4 Difficult to Quantify Impacts / Qualitative Impacts

The use of DERs as NWSs is a relatively recent phenomenon in the utility sector, and the technologies and programs that can be used as DERs continue to evolve quickly. It is possible that some impacts for a proposed DER solution may be difficult to quantify or value robustly yet could materially affect the conclusion of the BCA. LDCs may only incorporate those impacts required or permitted by the OEB's BCA Framework in their BCAs. For clarity, all societal impacts are excluded for consideration as part of Phase One of the BCA Framework.

In such cases, the LDC is encouraged to follow the process recommended by the NSPM for documenting non-monetary values in BCAs[17]:

- **Provide Quantitative Evidence.** It may be possible for a given impact or value stream that the LDC can provide quantitative evidence that supports a claim of value but is insufficient to monetize that value in the NPV calculation in the BCA test directly. *For example, the informational value of reducing the uncertainty of how able residents in dense, capacity-constrained areas are to deliver non-weather sensitive demand response would be applicable to the DST for distributors with several of such areas, but might not be applicable to the EST if such areas represent only a small portion of the overall energy system. While it may not be possible to precisely quantify the value of understanding the demand responsiveness of an LDC-specific demographic, the LDC could (for example) cite historical expenditures by the IESO through the Grid Innovation Fund as a proxy for the informational benefits of similar types of pilot. Though too imprecise to include in the calculation of the net benefits, the LDC could argue that if this proxy value were applied the net benefits of the NWS would exceed that of the alternative solutions.*

- **Define Metrics for Future Evaluation.** In some cases, impacts may be impossible to forecast with acceptable precision, but may be estimated ex-post reasonably reliably. Such ex-post evaluation results may then be used by other, similar projects in the future to estimate values for these impacts. *Continuing the example from above, if an evaluation finds that the targeted demographic can deliver the required demand response only if they are not permitted to opt out of a control event, the monetary value of that information could be evaluated as the difference between what the benefit actually delivered, and what would have been delivered had opt-outs been disallowed. This metric could be used for the ex-post valuation of the solution.*

Non-monetary estimates of value streams with quantifiable impacts as well as qualitative estimates of impacts for which quantitative estimates are unavailable should be specifically tied to the impact categories for one or the other (or both) of the BCA tests.

4.3.1.5 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 impact provides a benefit in the calculation of the Distribution Service Test (e.g., growth in distributed generation allows asset deferral) and a cost in the calculation of the Energy System Test (e.g., requiring the procurement of incremental ancillary services), then that impact must be account for symmetrically in both tests.

4.3.1.6 Incremental Analysis

In quantifying the benefits and costs of value streams, LDCs' BCAs should consider only incremental impacts, relative to the reference scenario that captures the business-as-usual

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

outcome. BCAs must articulate the reference scenario in enough detail such that it is evident to reviewers that the impacts considered in the BCA are, in fact incremental.

Reference scenarios should align with business-as-usual LDC 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 LDC 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 DERs. For example, if a utility provides customers 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 since these would be delivered even absent the program that is providing the NWS.

4.3.2 How to Apply What is Included

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

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

4.3.2.1 Net Present Value / Discounted Cash Flow Analysis

All value streams included in the BCA must be evaluated on a net present value basis, in constant dollars. Consistent with the IESO's guidance for the economic analysis of NWSs,[18] LDCs should use a 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 the LDC 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.

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

4.3.2.2 Discretionary vs. Non-Discretionary System Needs

DERs may serve as NWSs for 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 investment to meet a system need is *discretionary* if it is *not* required on a prudency basis (e.g., for safety/reliability).

- An investment to meet a system need is *non-discretionary* when it is an investment required as a prudent response by the LDC to ensure the reliability and continuity of its customers' service; i.e., where failing to meet the need would put the LDC out of compliance with applicable codes, standards, laws, or regulations.

Traditional non-DER investments to meet discretionary needs would typically require justification that the expected benefits of the project will outweigh its costs (i.e., some form of 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.

If the reference scenario requires *some* investment then need is non-discretionary.

Discretionary Investments

As per the recommendations of the BCA Subgroup report, in situations in which a LDC 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 LDC 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 benefits of all alternatives are compared in the BCA, and the option (including the do-nothing option) with the highest net benefit should be the most cost-effective solution.

Non-Discretionary Investments

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

- Because no BCA is 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 DER 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.

4.3.2.3 Study Period

The study period depends on whether the reference scenario investment is discretionary or not and on the test being applied.

For both the Distribution Service Test and the Energy System Test, where the investment need is *discretionary*, and a direct comparison is being made between two assets, the study period should be based on the longest expected service life among the alternatives being considered.

In contrast, where the investment need is non-discretionary, and the comparison is against a reference scenario in which a traditional poles-and-wires solution is being deployed on a prudency basis, the study period may vary by test type and the financial arrangement undertaken by the LDC to procure the DER.

For the Distribution Service Test, where the DER may defer or avoid a larger non-discretionary capital investment, the study period should be the payment period for the NWS and the corresponding deferral period of the pole-and-wires solution, whichever is longer. That is, the study period should cover the period in which the utility must make any incremental payments (and receive incremental benefits) compared to what would be expected with the deployment of the default traditional poles-and-wires solution in the reference scenario.

For example, suppose an LDC's technical analysis and load forecast suggests that contracting capacity from a third-party could defer the non-discretionary investment to address the need for an incremental distribution asset for five years. For the purposes of the Distribution Service Test the primary cost for consideration is the NPV of the annual contract cost for procuring the storage capacity and the primary benefit is the deferral benefit of delaying investment in the poles-and-wires for 5 years. This is calculated as the NPV of the distribution asset if it is installed on the default timeline less the NPV of the distribution asset if it is installed on the deferred timeline. In this case, only the *payment period* needs to be considered (assuming that payments cease when the distribution asset is eventually upgraded).

For the Energy System Test, in contrast, for a non-discretionary investment deferral, the study period should cover the entire lifetime of the DER, conditional on the following being true: a) it continues to provide broader energy system benefits (e.g., Ontario system coincident peak capacity value) even after the deferred asset is deployed, and b) the DER would not have been installed or procured absent the original deferral need (i.e., the benefits are truly incremental to the reference case).

The difference between the study periods applied for the two tests relates to each test's perspectives: for the DST only the period in which incremental benefits and costs accrue to *distribution service* received by the LDC's customers needs to be considered, whereas for the EST it is the period in which incremental benefits and costs to the entire electricity system accrue that is of interest.

4.3.2.4 Transparency and Validation

LDCs are expected to complete the reporting template (see Section 4.6) with a level of detail proportional to the materiality of the investments or payments being made, and consistent with the expectations outlined in Chapter 5 of the OEB's Filing Requirements for Electricity

Distribution Rate Applications[19] 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 distributor spending may be tested during a hearing. LDCs 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.

4.3.2.5 Projects and Programs

It is an objective reality that LDCs have well-established and long-standing processes and tools for planning, documenting (e.g., for purposes of cost recovery), and implementing poles-and-wires solutions to customer distribution service needs whereas few, if any, LDCs have established workflows designed to accommodate the adoption of DERs as NWSs.

This puts in place a significant structural disincentive for LDCs to pursue such opportunities, even when they may offer significant long-term distribution service benefits to consumers.

Where such legacy advantages (i.e., the long-established processes and resources) are in place, making a business case for DERs as NWSs may be challenging on a project-by-project basis. In many cases only very large projects with overwhelmingly positive net benefits for distribution service to customers may be deemed to be feasible.

LDCs 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 LDC 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).

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

Two illustrative examples of use-cases that might merit a programmatic (rather than a project-specific) approach are provided below.

<u>Example 1: EV-Driven Feeder Upgrade Deferral</u>

> An LDC, concerned about the implications of EV uptake in its service territory for feeder capacity, undertakes a locational forecast of EV adoption. It identifies that EV adoption over the next two years has a nearly certain probability of driving two feeder upgrades, and that EV adoption over the subsequent 3 years has a high probability of driving a further three feeder upgrades.
>
> Developing a separate BCA for each feeder would be resource-intensive and the timing for approvals (and any relevant coordination with the IESO as part of the IRRP process)

[19] 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

might make consideration of a DER impractical. The LDC might however undertake a BCA for a longer-term program for managed charging targeting local distribution needs.

The BCA could compare feeder upgrade deferral benefits to the incremental cost of deploying EV managed charging controls (and appropriate customer incentives) on a levelized cost basis, and assess the degree to which "headroom" (net benefit) of this comparison could support – across some number of projects/feeders – the costs of establishing the *program* infrastructure needed to support it.

<u>Example 2: Deferred Transmission Station Upgrade for New Connection</u>

Property developers have submitted connection requests for several new sub-division developments that will be adjacent to an existing sub-division currently adequately served by its transmission station. The anticipated load of all of the new developments would require a substantial upgrade to the TS serving the existing sub-division.

The LDC, noting that the timing of residential development connection requests is highly uncertain, believes that it may be able to defer the TS upgrade cost-effectively by working with developers to deploy batteries (under utility control) to new construction homes, and to offer utility-controlled batteries to owners of the existing homes served by the TS. The utility has identified the minimum number of batteries that must be installed to defer the TS upgrade, but would like the flexibility to increase the number batteries it deploys as the certainty of the connections increases over time.

In this case, the LDC could develop a BCA that compares the avoided cost benefit of capital deferral to the cost of incenting developers to install battery storage and smart controls in the newly built as well as existing homes.

This comparison could be performed on a levelized cost-basis, for each step-change in the sizing of the (potentially) necessary TS. Net benefits on a levelized cost basis could define the "headroom" available for program administration costs. The BCA would demonstrate the cost-effectiveness of allowing the utility flexibility to respond to short-term changes in developer needs with DERs instead of traditional wired solutions.

4.3.2.6 Resource Procurement Approach

LDCs may procure DERs themselves or through a third party or parties.

Third-party procurement, for example via a demand response (DR) aggregator, may be preferred in use-cases where the need is relatively predictable and can be implemented without requiring recurring operational direction from the utility control room, for example when using DERs to defer investments in transformer station upgrades to serve predictable summer peak load growth in an intensifying residential neighbourhood.

LDCs may prefer to procure and operate DERs themselves when the needs being serviced require greater operational oversight (e.g., for emergency or contingency needs), though this may change over time as the market for third-party DER offerings develops.

For the purposes of quantifying benefits, the resource procurement approach will affect the certainty with which a utility can quantify bulk energy system benefits in addition to just the distribution service benefits. For example, if an LDC deploys a utility-scale storage solution to defer a distribution system need, that LDC can with reasonable certainty quantify the energy system value that storage solution might deliver to the bulk energy system following the end of the deferral period. In contrast, if the storage solution is owned and operated by a third-party, unless that third party has entered into a contract with the IESO to provide that bulk energy system value there is no guarantee that the battery might not be removed following the expiry of the distribution system need to serve a deferral need for another LDC.

Utility BCAs should carefully delineate between contracted (certain) and hypothesized potential benefits when quantifying the impacts of third-party DERs.

4.4 Cost Effectiveness Tests

This section of the BCA Handbook defines the two cost-effectiveness tests relevant to LDC BCAs when considering DERs as 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.

LDCs wishing to recover costs associated with DERs or DER services as an NWS must calculate (and present to the OEB) the benefits and costs prescribed by the Distribution Service Test. LDCs may also elect to calculate the benefits and costs prescribed for the Energy Service Test.

As noted above, the comprehensive valuation of all benefit streams is not required if it can be demonstrated that those benefits streams that *have* been valued indicate that the DER in question is the least-cost (i.e., most cost-effective) solution. Benefits not quantified as part of the BCA, however, cannot later be used by the LDC in supporting a proposal for LDC incentives for that DER (in the case of third-party LDCs).

Comprehensive valuation of material incremental costs associated with the project in question is required.

The OEB's BCA Framework will continue to evolve, and as part of the Phase 2 development LDCs should expect potentially significant changes to be applied to the methods and assumptions required for the Energy System Test. The Distribution Service Test 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 DER use-cases.

4.4.1 Distribution Service Test

The Distribution Service Test is a new cost-effectiveness test in the Ontario energy BCA landscape in name only. It is analogous to the IESO's Program Administrator Cost[20] test but limited to the benefits within the jurisdiction of the distribution utility.

[20] See Section 3.3 of Independent Electricity System Operator, ***Cost Effectiveness Guide for Energy Efficiency***, May 16, 2022

Independent Electricity System Operator, ***Cost Effectiveness Guide for Energy Efficiency***, May 16, 2022

The Distribution Service Test 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 DST will be the main test used to test the cost-effectiveness of the NWS considered by an LDC.

NWSs can, as noted above, be used to meet either discretionary or non-discretionary system needs.

Where the need being met is discretionary, and the default solution in the reference scenario also requires some assessment of cost-effectiveness (if not an explicit BCA) or is to do nothing, the net benefits (i.e., benefits minus costs) are calculated for each alternative project, and they are compared. The project with highest expected value net benefits is the most cost-effective.

Where the need being met is non-discretionary, the costs of the proposed DER are compared to the deferral benefits it offers (i.e., the benefit of deferring the required investment in the reference scenario) and any other relevant benefits. Where net benefits are positive, or the ratio of benefits to costs exceeds 1 in expected value, the DER project is cost-effective.

Because the DST is tightly focused on the net value of a DER for distribution service, it excludes some value streams traditionally considered in Ontario BCAs for DERs.

The primary impacts LDCs should consider under the Distribution Service Test are provided in Table 4, below.

Table 4. DST Impact Categories

Impact	Source	Quantitative	Qualitative
BENEFITS			
Distribution Capacity	**Location-specific Deferred Distribution Capacity Costs**	✓	
Reliability (Avoided Restoration Costs)	**Marginal Cost of the Reliability Investment (Project & location-specific)**	✓	
Resilience (Avoided Outage Costs)	**Customer-specific Value of Electricity Service [21]**	✓	✓
Innovation & Market Transformation	**TBD**		✓
Planning Value	**TBD**		✓
COSTS			

[21] Assuming the customer would be willing to pay the same retail rate they pay for electricity, to avoid an outage

Impact	Source	Quantitative	Qualitative
Distributor Cost		✓	
DER Capacity Acquisition Cost	**Overnight Capital and O&M Cost, or Contract or Incentive Payment Cost, etc.**	✓	
Program Costs	**Project/Program-specific admin costs (including EM&V, incentives)**	✓	
Incremental Distribution and DMS Costs	**Project-specific additional T&D costs**	✓	
Risks (Distribution System)	**TBD**		✓
AMBIGUOUS VALUE *(Impacts may be a cost or a benefit)*			
Avoided/Incremental Distribution O&M Costs	**Project and utility-specific avoided O&M expenses**	✓	
Avoided/Incremental Distribution Ancillary Services	**No equation provided** **Equipment/solution-specific**	✓	✓

In some cases, LDCs may find that impacts listed separately above are – as a result of how they are estimated – combined into a single value stream. For example, estimated avoided O&M costs might be combined with estimated avoided/deferred construction costs in the distribution capacity benefit. In such cases, LDCs may note where such impacts have been combined and should provide some explanation as to why they cannot be broken out into their component categories.

4.4.2 Energy System Test

The Energy System Test evaluates all the energy system impacts to all customers in Ontario. The outcome of a BCA evaluated under the EST is that, as per the Report of the BCA Subgroup:

"*A solution is preferred if it results in the greatest net energy system benefit to energy customers overall. This aligns with two of the traditional cost-effectiveness tests, the 'program administrator cost test' and the 'total resource cost test'… The test determines whether provincial ratepayers as a whole will be better off by implementing the DER as opposed to the alternatives.*"[22]

The EST does not consider societal costs, it focuses only on the net benefits to provincial ratepayers.

LDCs are not required to complete the EST as part of their BCA, but are encouraged to do so, particularly if they believe the DER offers significant benefits beyond those of distribution service. LDCs are strongly encouraged 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 LDC's BCA needs, it may use some of the sources recommended below to provide interim values. Benefits estimated by the

[22] EB-2021-0118, *Framework for Energy Innovation – Report of the BCA Subgroup*, June 8, 2022, Page 21

IESO IRRP Technical Working Group will always supersede interim values specified below, provided these are received before the LDC has submitted its BCA to the OEB (as part of an application). Where input values are not available from the IESO prior to the LDC's application, the application will be assessed on the best information available at the time of – and included in – the application.

Table 5. EST Impact Categories

Impact	Source	Quantitative	Qualitative
BENEFITS			
Distribution Value	**Benefits calculated for the DST may also be included in the EST (care should be taken to avoid double-counting)**	✓	✓
Transmission Capacity	**Provided by IESO in IRRP process. Place-holder values may be drawn from IESO DER potential study.[23]**		
Avoided Energy Costs	**Provided by IESO in IRRP process. Place-holder values may be drawn from the IESO CDM Cost-Effectiveness Tool[24]**	✓	
Avoided Generation Capacity Costs	**Provided by IESO in IRRP process. Place-holder value may be drawn from the IESO IRRP Guide for NWAs: $144/kW-year[25]**	✓	
Reliability (Net Avoided Restoration Costs)	**Same as DST**	✓	
Resilience (Net Avoided Outage Costs)	**Same as DST**	✓	✓
Planning Value	**TBD**		✓
Innovation & Market Transformation	**TBD**		✓
COSTS			
System Costs		✓	

[23] See table C-2 of

Dunsky, prepared for IESO, ***Ontario's Distributed Energy Resources (DER) Potential Study – Volume II: Methodology & Assumptions***, September 28, 2022

[24] Accessible at

https://www.ieso.ca/en/Sector-Participants/Energy-Efficiency/Evaluation-Measurement-and-Verification

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

Impact	Source	Quantitative	Qualitative
DER Capacity Acquisition Costs	**DER capacity and energy acquisition costs**	✓	
Program Costs	**Project/Program-specific admin costs (including EM&V, incentives)**	✓	
Risks (Energy System)			✓
AMBIGUOUS VALUE			
Avoided/Incremental System O&M Costs	**System-level O&M costs/benefits due to adoption of Energy System DER**	✓	
Avoided/Incremental System Ancillary Services	**System-level Ancillary Services costs/benefits due to adoption of Energy System DER**	✓	✓

4.5 Benefits and Costs

Considerable range exists in the degree to which BCA Handbooks in other jurisdictions prescribe the methods for estimating the impacts required for the various cost-effectiveness tests. The New York utilities – whose BCA Handbooks all spring from a common template first developed in 2016 – provide detailed formulae for each impact, including for distribution capacity benefits (see Table 1 for the New York utilities BCA Handbooks noted here). In contrast, National Grid's Rhode Island BCA TRM simply indicates that "*Distribution Capacity benefit is based on the direct deferred distribution infrastructure due to the implementation of the NWA. The value includes such inputs as deferred capital expenditure, deferred O&M, and deferred taxes over the expected contract timeframe of the NWA.*"[26]

For the purposes of the Project Plan, an example of the more detailed and prescriptive approach has been drawn from the NYSEG BCA Handbook[27]. The degree to which the draft OEB Handbook includes this level of specificity is expected to be driven in part by feedback provided by stakeholders on this Project Plan. The balance sought is one that provides sufficiently specific direction to LDCs to assist their staff in developing the BCA without overly constraining them, and potentially restricting the possibilities for innovative solutions to improving distribution service value. At present, the principal argument against the formulaic approach (such as the example of the NYSEG BCA Handbook[28]) is that Guidehouse expects that in most cases impacts will be estimated as "custom" values, drawn from the utility's available costing data for non-discretionary default poles-and-wires solutions, rather than drawn as generic values from a third-party source to be applied to the formulas.

Below is a brief description of each of the benefit and cost streams required – where applicable – for cost-effectiveness testing, discussion of acceptable sources of data, and representative

[26] Narragansett Electric Company d/b/a National Grid, National Grid's Technical Reference Handbook for the Benefit-Cost Analysis of Non-Wires Alternatives in Rhode Island, May 2021

[27] NYSEG, Benefit Cost Analysis Handbook / Version 3.0, June 2020

[28] Ibid

equations to apply to those data to derive net present values, and other general methodological considerations.

Some of the content in this section of the project plan is intended to provide an outline. Additional content will be developed further as part of the draft BCA Framework.

4.5.1 Distribution Service Test Benefits and Costs

This section describes each benefit/cost stream that should be considered as part of the DST. Table 6 summarizes key considerations regarding the applicability of each impact, while the subsections below describe the recommended methodology for quantifying the estimated benefit or cost.

Not all impacts are expected to relevant for all BCAs. Some impacts may be inapplicable, negligible, duplicative with other impacts, or difficult to quantify. Nonetheless, LDCs should provide justification for any impacts which are excluded from the BCA.

Table 6. Applicability of DST Impacts

Impact	Description	Considerations for Applicability
BENEFITS		
Distribution Capacity (Avoided Infrastructure Costs)	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 generally the primary target benefit of NWS projects and should be included in all related BCAs.
Reliability (Avoided Restoration Costs)	Accounts for avoided costs of restoring power during outages	For most DERs, this benefit will not be quantified as LDCs will need to fix the cause of the outage regardless of whether the customer can operate autonomously through the use of the DER. In rare cases, avoided restoration costs may be relevant if the DER are used in a manner that would be prevent outages from occurring and do so to a greater extent than the reference case / traditional upgrade.
Resilience (Avoided Outage Costs)	Accounts for customer outage costs due to a reduction in frequency and duration of outages	For many DERs, this benefit will not be applicable. For DER such as energy storage and dispatchable DG with islanding capabilities, this benefit may be applicable if the DER enables customer to operate in islanded mode while the grid outage is being addressed. In rare cases, avoided outage costs may also be applicable if the DER are used in a manner that would be prevent outages from occurring and do so to a greater extent than the reference case / traditional upgrade.
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 value stream is often related to pilot and demonstration projects which can provide significant learning value to inform more significant future investments or programs.

Impact	Description	Considerations for Applicability
Planning Value	Accounts for value of optionality for LDC planning	This value stream may be notable for some NWS projects. For example, a mobile storage system may be redeployed to a new constrained location after the initial deferral period ends. Moreover, NWSs often present optionality that can help LDCs to manage costs and uncertainty. For example, a NWS may allow the LDC to defer for longer than originally planned as a result of slower-than-planned load growth, or by adding additional DER capacity at a later date.
COSTS		
Distributor Cost	Accounts for incremental costs incurred by LDCs; see details below for each relevant sub-category	See considerations below by sub-category.
DER Capacity Acquisition Cost	Cost includes the incremental cost to acquire, install, and operate the DER	The nature of these costs may vary depending upon the type of DER being utilized and the method of acquiring DER capacity. This includes capital and operating costs associated with utility-owned DER, as well as incentives paid by the LDC to DER providers for third-party DER. LDCs should take care to differentiate these costs from Program Costs (including program administration, marketing, and measurement and verification), as well as Incremental Distribution and DMS Costs (including incremental costs for systems to manage DER dispatch).
Program Costs	Costs to manage the NWS project or program	Examples of relevant costs include incremental costs for third-party contractors and/or utility staff – relative to such costs for the reference case – for the following: • Program administration • Sales & marketing • Resource procurement (only costs to manage procurement; excludes DER Capacity Acquisition Cost) • Measurement & verification
Incremental Distribution and DMS Costs	Incremental costs to the LDC associated with increased needs for distribution equipment and distribution management software (DMS)	Relevant costs include incremental costs for software to effectively monitor and dispatch DER associated with the NWS solution, as well as incremental distribution equipment to be able to safely interconnect the DER.
Risks (Distribution System)	Accounts for uncertainty which may present schedule, cost, or performance risk	Note that many uncertainties may be accounted for in other value streams, for example by using de-rating factors to help ensure sufficient DER capacity is available when needed. For NWSs, this impact 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.
AMBIGUOUS VALUE		

Impact	Description	Considerations for Applicability
Avoided/Incremental Distribution O&M Costs	Includes the avoided or incremental distribution operation and maintenance (O&M) costs to the LDC associated with the adoption of the NWS	This impact may be applicable whenever the NWS causes a change in utility costs associated with operating and maintaining the distribution system. The impacts here should be considered relative to expected costs under the reference scenario. LDCs should take care to avoid duplicating these impacts with those above. For example, it is possible that LDC O&M costs for traditional infrastructure in the reference case may be embedded within Avoided Distribution Capacity Infrastructure. Other O&M costs may also be captured within Program Costs or Incremental Distribution and DSM Costs. This category also includes reduced/incremental expenses not directly tied to avoided or deferred system investment from NWS. It may, for example, 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. Such impacts are often expected to be difficult to quantify and minimal. However, they may be notable for NWS-related investments with broader value beyond the specific investment being deferred or avoided. See section 4.3.1.4 for guidance regarding qualitative and difficult-to-quantify impacts.
Avoided/Incremental Distribution Ancillary Services	Incremental costs to the LDC associated with increased needs for ancillary services due to the adoption of DER and/or incremental benefits of using DER to provide ancillary services	This impact may be applicable as a cost if the DER employed for the NWS will require the LDC to make investments to manage power flow issues. For example, deploying distributed solar as a NWS may require greater investment in voltage control capabilities on the circuit. LDCs should take care to avoid duplication with other impacts (e.g., DER Capacity Acquisition Cost, Incremental Distribution and DMS Costs). Alternatively, this impact may be applicable as a benefit if the DER are planned to be used to provide distribution-level ancillary services (e.g., volt/VAR support). If this benefit is excluded, LDCs should provide a qualitative justification for exclusion.

4.5.1.1 Avoided Distribution Capacity Infrastructure

The value of Avoided Distribution Capacity Infrastructure generally stems from deferral or avoidance of a traditional infrastructure investment as a result of the adoption of the NWS. In general, there are three approaches to quantifying this value:

- Change in NPV – accounts for the difference in net present value between the traditional investment made without the NWS vs deferring the investment to a future date, resulting a lower NPV of the cost of the traditional investment

- Carrying cost – accounts for the avoided incremental increase in annual revenue requirement as a result of deferring the traditional investment

- Marginal capacity value – accounts for the incremental value of DER capacity on constrained circuits

Change in NPV

This approach is useful for the deferral or avoidance of a specific traditional investment with a project-specific cost and predicted deferral timeframe. This approach accounts only for avoided capital costs, so any avoided operating costs must be accounted for within Avoided/Incremental Distribution O&M Costs (Section 4.5.1.7). The benefit value may be calculated according to Equation 1, which is further described in Table 7.

Equation 1. Avoided Distribution Capacity Infrastructure – Change in NPV

$$Benefit = NPV(ProjectCost_{Y1}, Y1, r) - NPV(ProjectCost_{Y2}, Y2, r)$$

Table 7. Avoided Distribution Capacity Infrastructure Parameters – Change in NPV

Parameter	Definition	Source	Note
NPV ($)	Net present value as a function of cost, time, and discount rate	Calculation	See Section 4.3.2.1 for guidance.
$ProjectCost_Y$ ($)	Real cost (constant dollar value without adjusting for future inflation) of the traditional investment in a given year	LDC planning estimate	The cost of the traditional investment (*ProjectCost*) should be justified based upon planning estimates which account for the project- and location-specific capital costs for deploying the traditional infrastructure. In many cases, the real cost is expected to be the same in *Y1* and *Y2*, so any deviations must be justified based upon expected non-inflationary cost impact.
Y_1 (years)	Years until traditional investment is planned to be made in the reference case (without the NWS)	LDC planning estimate	
Y_2 (years)	Years until traditional investment is expected to be made as a result of the NWS ($Y_2 – Y_1$ = deferral period)	LDC planning estimate	The timeline for deferral may have significant uncertainty, and the traditional investment may actually end up occurring sooner or later depending upon factors including load growth and the performance of NWS resources. Such uncertainties may have asymmetric impacts – for example, load growth that is 1% higher than projected may reduce deferral by 1 year, while load growth that is 1% lower than projected may increase deferral by 5 years. See Section 4.3.1.3 for guidance on treatment of uncertainties, which may be captured within Planning Value (Section 4.5.1.5) and/or Risks (Section 4.5.1.7)
r (%)	Discount rate	Standard value (4%)	See Section 4.3.2.1 for guidance.

Carrying cost

As with the NPV approach above, this approach is useful for the deferral or avoidance of a specific traditional investment with a project-specific cost and predicted deferral timeframe. In this case, however, the benefit is annualized and includes O&M costs. The benefit value may be calculated according to Equation 2.

Equation 2. Avoided Distribution Capacity Infrastructure – Carrying cost

$$Benefit_Y = \sum_Y ProjectCost \times r_{carry}$$

Where,

- *Y* = year in which deferral or avoidance of the traditional investment is achieved

Parameter	Definition	Source	Note
ProjectCost ($)	Real cost (constant dollar value without adjusting for future inflation) of the traditional investment	LDC planning estimate	The cost of the traditional investment (*ProjectCost*) should be justified based upon planning estimates which account for the project- and location-specific capital costs for deploying the traditional infrastructure.
r (%)	Fixed carrying charge, which effectively represents the incremental annual revenue requirement associated with the traditional investment	May be utility- and/or project-specific	The carrying charge represents incremental annual revenue requirement as a percentage of the initial capital cost. The value is a function of the weighted cost of capital (mix of equity and debt), taxes, insurance, and equipment life. Other O&M costs may also be included in the carrying charge. LDCs must be cautious not to double-count Distribution O&M benefits when considering them in Section 4.5.1.7

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 benefit value may be calculated according to Equation 3, which is further described in Table 8:

Equation 3. Avoided Distribution Capacity Infrastructure

$$Benefit_Y = \sum_V \sum_C \frac{\Delta PeakLoad_{y,r}}{Loss\%_{Y,b \rightarrow r}} \times DistCoincidentFactor_{C,V,Y} \times DeratingFactor_Y \times MarginalDistCost_{C,V,Y,b}$$

Where,

- *C* = Constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of the distribution system[29]
- *V* = Voltage level (e.g., primary, and secondary)
- *Y* = Year
- *b* = Bulk System
- *r* = Retail Delivery or Connection Point

The equation parameters, their definition, and associated source are presented in Table 7, below.

Table 8. Avoided Distribution Capacity Infrastructure Parameters

Parameter	Definition	Source	Note
MarginalDistCost ($/MW-yr)	Marginal cost of the distribution equipment from which the load is being relieved	Utility-specific data, or project-specific , applicable to all projects of the same utility	It is assumed that the marginal cost of service is based on the bulk system (“b”). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment specific marginal costs of service should be used in most cases. In limited circumstances the use of the system average marginal cost may be acceptable, for example, the evaluation of energy efficiency programs. If capital and O&M avoided costs cannot be separated, LDCs must be cautious not to double-count Distribution O&M benefits when considering them in Section 4.5.1.7.
ΔPeakLoad (MW)	Nameplate demand reduction of the project at the retail delivery or connection point (r)	LDC, as this is project-specific.	Positive value represents a reduction in peak load. The timing of benefits realized from peak load reductions are project- and/ or program-specific. It is assumed that a peak load reduction impact will produce benefits in the year of the impact. Once the peak load reduction is no longer enough to avoid or defer investment and infrastructure must be built, benefits should not be recognized from that point forward.
Loss% (%)	Loss percent between the bulk system (b) and the retail delivery or connection point (r). This is the sum of the transmission and distribution system loss percent values	Utility-specific data	It is used to adjust the *ΔPeakLoad* (MW) parameter to the energy system level

[29] Where the use of system-wide marginal cost values is required, this subscript is not applicable

Parameter	Definition	Source	Note
DistCoincidentFactor (dimensionless)	Input that captures the contribution to the distribution element's peak relative to the project's nameplate demand reduction.	Project-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 (dimensionless)	Generic factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours.	Project-specific, utility	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.

4.5.1.2 Reliability (Net Avoided Restoration Costs)

Avoided Restoration Costs may be calculated according to Equation 4, which is further described in Table 8.

Equation 4. Reliability (Net Avoided Restoration Costs)

$$Benefit_Y = MarginalDistCost_{R,Y}$$

Where,

- R = Reliability constraint on an element of distribution
- Y = Year

The equation parameters, their definition, and associated source are presented in Table 8, below.

Table 9. Reliability (Net Avoided Restoration Costs) Parameters

Parameter	Definition	Source	Note
MarginalDistCost ($/yr)	Marginal cost of addressing restoration needs, which are avoided as a result of the NWS, and which would not be avoided as a result of the traditional investment	Project- and location-specific. A system value is not applicable	This benefit is applicable to NWSs that are able to provide functionally equivalent reliability as compared to the reliability provided by a traditional distribution reliability investment that would otherwise have been built.

4.5.1.3 Resilience (Net Avoided Outage Costs)

Benefits from avoided outages may be calculated according to Equation 5, which is further described in Table 9.

Equation 5. Net Avoided Outage Costs

$$Benefit_Y = \sum_C ValueofService_{C,Y,r} \times AverageDemand_{C,Y,r} \times SAIDI_Y$$

Where,

- *C* = Customer Class (residential, commercial, industrial)
- *R* = Reliability constraint on an element of distribution
- *Y* = Year

The equation parameters, their definition, and associated source are presented in Table 9, below.

Table 10. Resilience (Net Avoided Outage Costs) Parameters

Parameter	Definition	Source	Note
This section will be further developed in the draft BCA Framework.			

4.5.1.4 Innovation & Market Transformation

Certain pilot costs may be excluded or adjusted within the BCA if they are not reflective of unit costs at scale. Alternatively, the benefit of learning value may be quantified. Only one approach may be used – LDCs may not both exclude pilot costs and add quantified future benefits within the BCA.

4.5.1.5 Planning Value

These benefits may be difficult to quantify and may often be tied to asymmetric outcomes for relatively symmetric probabilities.

4.5.1.6 This section will be further developed in the draft BCA Framework. Distributor Cost

This section will be further developed in the draft BCA Framework. DER Capacity Acquisition Costs

DER Capacity Acquisition Costs may be calculated according to Equation 6, which is further described in Table 10.

Equation 6. DER Capacity Acquisition Costs

$$Cost_Y = \sum_M \Delta DERAcquisitionCost_{M,Y}$$

Where,

- *M* = Measure (DER)
- *Y* = Year

Table 11. DER Capacity Acquisition Costs Parameters

Parameter	Definition	Source	Note
∆DERAcquisitionCost ($/yr)	This section will be further developed in the draft BCA Framework.		

Program Costs

Program Costs may be calculated according to Equation 6, which is further described in Table 10.

Equation 7. DER Program Costs

$$Cost_Y = \sum_M \Delta DERProgramCost_{M,Y}$$

Where,

- *M* = Measure (DER)
- *Y* = Year

Table 12. DER Capacity Acquisition Costs Parameters

Parameter	Definition	Source	Note
∆DERProgramCost ($/yr)	This section will be further developed in the draft BCA Framework.		

Incremental Distribution and DMS Costs

Incremental Distribution and DMS Costs may be calculated according to Equation 8, which is further described in Table 13.

Equation 8. Incremental Distribution and DMS Costs

$$Cost_Y = \sum_M \Delta DMSCost_{M,Y}$$

Where,

- *M* = Measure (DER)
- *Y* = Year

Table 13. Incremental Distribution and DMS Costs Parameters

Parameter	Definition	Source	Note
Δ*DMSCost* ($/yr)	This section will be further developed in the draft BCA Framework.		

4.5.1.7 Risks

These benefits may be difficult to quantify (see Section 4.3.1.4 for guidance) and may often be tied to asymmetric outcomes for relatively symmetric probabilities (see Section 4.3.1.3 for guidance), where Risks are the downside counterpart to upside Planning Value (see Section 4.5.1.5).

4.5.1.8 This section will be further developed in the draft BCA Framework. Avoided/Incremental Distribution O&M Costs

Avoided/Incremental Distribution O&M Costs may be calculated according to Equation 9, which is further described in Table 14.

Equation 9. Avoided/Incremental Distribution O&M Costs

$$Cost_Y = \sum_M \Delta Expenses_{AT,Y}$$

Where,

- *AT* = Activity Type (line crews to replace equipment, engineering review of DER interconnection applications, responding to calls associated with DER)T
- *Y* = Year

Table 14. Avoided/Incremental Distribution O&M Costs Parameters

Parameter	Definition	Source	Note
Δ*Expenses* ($/yr)	This section will be further developed in the draft BCA Framework.		

4.5.1.9 Avoided/Incremental Distribution Ancillary Services

Avoided/Incremental Distribution Ancillary Services may be calculated according to Equation 10, which is further described in Table 15.

Equation 10. Avoided/Incremental Ancillary Services Costs

$$Cost_Y = \sum_M \Delta AncServices_{M,Y}$$

Where,

- *M* = Measure (DER)
- *Y* = Year

Table 15. Avoided/Incremental Ancillary Service Costs Parameters

Parameter	Definition	Source	Note
Δ*AncServices* ($/yr)	This section will be further developed in the draft BCA Framework.		

4.5.2 Energy System Test Benefits and Costs

This section contains a description of each of the impact categories that could be considered as part of the EST for review by the OEB and stakeholders, as part of the current consultation. The intent is for the BCA Handbook to include a section for EST impacts that mirrors the DST set out in Section 4.5.1 above.

There is overlap between the impact categories included in the DST and the EST. Therefore, the section below focuses on incremental impacts relative to the DST. It is expected that LDCs will conduct DSTs ahead of performing an EST, and they should therefore leverage DST results for impacts common to both tests, within the 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 DERs 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 some collective BCA across both perspectives, as doing so risks double-counting.

LDCs are encouraged to engage with the IESO IRRP process as soon as possible in the BCA development process to identify any additional bulk system benefits or refine the values used for initial development of the EST. Generally, LDCs may use the IESO's published CDM avoided costs for the purposes of valuing any bulk system energy benefits that the DERs deliver as preliminary values to use as part of IRRP process discussions.

Proponents may not have a detailed understanding of the energy system impacts of the NWS they are considering. Proponents are encouraged to complete the EST with placeholders and generic values (e.g. $144/MW-yr for the system capacity value from the NWA guide). However, proponents must be aware that any assessment of bulk system benefits undertaken by the IESO will displace any previously developed EST net benefit values (placeholders or not), further emphasizing the need for proponents to engage with the IESO early on in the process.

This section of the project plan is intended to provide an outline of the benefits and costs that may be considered as part of the EST. The content of the individual subsections will be developed further as part of the draft BCA Framework.

4.5.2.1 Avoided Energy Costs

4.5.2.2 This section will be further developed in the draft BCA Framework. Avoided Generation Capacity Costs

This section will essentially reflect the Avoided Distribution Capacity Infrastructure costs from section, but with a replaced capacity value of $144/MW-yr (as a placeholder).

4.5.2.3 Reliability (Net Avoided Restoration Costs)

Reliability benefits at the energy system level will include reliability benefits from the DST, along with any additional transmission-level benefits the NWS may provide. Please refer to section 4.5.1.2 for direction on how to calculate reliability benefits.

4.5.2.4 This section will be further developed in the draft BCA Framework. Resilience (Net Avoided Outage Costs)

Resilience benefits at the energy system level will include resilience benefits from the DST, along with any additional transmission-level benefits the NWS may provide. Please refer to section 4.5.1.3 for direction on how to calculate resilience benefits.

4.5.2.5 This section will be further developed in the draft BCA Framework. Innovation and Market Transformation

4.5.2.6 This section will be further developed in the draft BCA Framework. System Cost

4.5.2.7 This section will be further developed in the draft BCA Framework. Risks

4.5.2.8 This section will be further developed in the draft BCA Framework. Energy Generation and Losses

4.5.2.9 This section will be further developed in the draft BCA Framework. System O&M

4.5.2.10 This section will be further developed in the draft BCA Framework. Ancillary Services

4.6 This section will be further developed in the draft BCA Framework. Reporting Requirements

LDCs are expected to document their proposals for DERs as 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.

As per the CDM Guidelines, LDCs should explain the proposed DER in the context of the LDC's DSP, including providing details on the system need that is being addressed, the infrastructure investments that are being avoided or deferred as a result of the DER, and the prioritization of the proposed DER relative to other system investments in the DSP.

The BCA Handbook's section on Reporting Requirements is expected to include two sub-sections. The first will describe the reporting format LDCs are expected to adhere to in providing the narrative description of their BCA, the second will describe the content of the Excel-based output reporting template.

4.6.1 Reporting Format / Template

LDCs are required to report on their proposed DER as NWSs using a similar format to that used by the distributor for justifying capital expenditures within the DSP. LDCs must specify: the need, the alternatives considered, the quantitative results of the BCA, any qualitative considerations or supporting evidence for the for the BCA, the alternative selected, the risks of that selection and the mitigation to be applied. This will also apply in cases where a BCA was undertaken but a traditional poles-and-wires solution was determined to be the preferred solution.

- **Need.** A narrative description of system requirements and the associated context. This should specify whether the need is discretionary or non-discretionary.
- **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.
- **BCA Results.** A table of the values for the monetary impacts included in the BCA, the quantitative outcome of the BCA itself, and a written summary of the outcome of the analysis. This section may identify key uncertainties and how they have been addressed quantitatively.
- **BCA Considerations.** A summary of the qualitative considerations or any additional supporting evidence for the preferred alternative. It is in this section that LDCs should identify difficult-to-quantify impacts and qualitative impacts.
- **Outcome.** A short, formal, confirmation of the alternative selected, and the essential specifications of that alternative.
- **Risks and Mitigation.** Identification of key risks associated with the alternative and the mitigation and monitoring to be put in place by the LDC.

4.6.2 Data Output Requirements

The BCA Handbook 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 LDC 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 LDC will be required to provide both its estimate of the NPV of the distribution capacity benefit, but also the capacity enabled by the DER in question.

4.7 Examples

The project plan includes an outline for one example: battery storage application as an NWS. This example, and two more, will be included with considerable additional detail in the draft Handbook. Examples are expected to be between 5 – 10 pages in length. Values (e.g., of impact streams) will be illustrative.

LDC stakeholders are encouraged to provide specific recommendations for distribution system needs and the corresponding DER solutions that they would like to see illustrated by example.

4.7.1 Example 1: Storage

As identified in section 4.6, the proponent must develop an application that includes a description of the need and expected outcome as a result of the investment, a description of the asset/program, its outcome, an expenditure plan, the alternatives considered, and an overview execution and mitigation plan. This section provides an example of an LDC intending to apply to deploy a 4-hour battery storage system in a remote community to defer the need for a traditional poles and wires solution for (at least) the next 4 years.

4.7.1.1 Need

In this first section, to the LDC should provide a summary-level description of their need and the expected outcome of this application, as well as an overview of the expected capital expenditure and a descriptive summary of the solution.

4.7.1.2 Alternatives Considered

In this section, the proponent is encouraged to provide a detailed technical and operational description of their proposed investment.

The proponent is encouraged to provide a description of each of the alternatives considered as part of this process.

In the context of the battery storage example, the proponent could discuss the following alternatives:

1) Do nothing
2) Traditional poles and wires solution
3) Proposed plan
4) Accelerated pace for proposed plan

4.7.1.3 BCA Results

This is where the proponent provides the results of the BCA analysis they have conducted. Guidehouse expects an Excel template to be made available to proponents to ensure that they can convey the inputs, assumptions, and results of their assessment efficiently and in a streamlined manner. Below are examples of DST and EST table results that would be provided under this section.

Table 16. Battery Storage Example – DST Results

Impact	Distribution Service Test		
	Value	Source	Notes
BENEFITS			
Avoided Distribution Capacity			
Reliability (Net Avoided Restoration Costs)			
Resilience (Net Avoided Outage Costs)			
Planning Value	**N/A**		
COSTS			
Distributor Cost			
DER Capacity Acquisition Cost			
Program Costs			
Incremental Ancillary Service Costs			
Incremental Distribution and DMS Costs			
Risks (Distribution System)	**N/A**		
AMBIGUOUS VALUE			
Avoided/Incremental Distribution O&M Costs			
Avoided/Incremental Distribution Ancillary Services			

Should the proponent decide to conduct an EST, this is the section where the EST results of the NWS will also be provided.

Table 17. Battery Storage Example – EST Results

Impact	Distribution Service Test		
	Value	Source	Notes
BENEFITS			
Avoided Energy Costs			
Avoided Generation Capacity Costs			
Reliability (Net Avoided Restoration Costs)			
Resilience (Net Avoided Outage Costs)			

Planning Value	N/A
Innovation & Market Transformation	N/A
COSTS	
System Costs	
DER Capacity Acquisition Costs	
Program Costs	
Added Ancillary Service Costs	
Risks (Energy System)	N/A
AMBIGUOUS VALUE	
Avoided/Incremental T&D and DSP Costs	
Avoided/Incremental System O&M Costs	
Avoided/Incremental System Ancillary Services	

4.7.1.4 BCA Considerations

4.7.1.5 This section expands upon the introductory outcomes' description. This is where the proponent provides additional detail about their intent for investing in this solution. Outcome

This section should include a short statement formally identifying the outcome of the BCA and the alternative with which the LDC proposes to proceed.

For example: "*Based on the finding that deferring investment in distribution asset X for Y years through the use of the proposed battery alternative yields a net benefit of $Z, with a benefit to cost ratio of R, LDC ABC plans to proceed with the procurement of a battery meeting the specifications described in Section 4.7.1.2.*"

4.7.1.6 Execution Risk and Mitigation

Here, proponents are required to provide additional context in terms of risks and their associated mitigations. For example:

Table 18. Battery Storage Example - Risks and Mitigation

Risk Category	Assessment	Mitigation
Procurement and Logistics	Supply chain constraints are affecting worldwide availability of lithium-ion batteries	Include vendor early on in the project
Real Estate	Construction of this NWS requires acquisition of new property, resulting in financial and timing risks	Providing appropriate lead times to allow for sufficient time to secure real estate property and involving site owners early in the project
Telecommunications	Cellular strength may not be sufficient to monitor battery system performance	Verifying signal strength before selecting the site and the battery system

4.7.2 Example 2: TBD

A second example will be developed in this section according to the structure presented above.

4.7.3 Example 3: TBD

A third example will be developed in this section according to the structure presented above.