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Framework for Energy Innovation

Report of the BCA Subgroup

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Submitted to:
The Framework for Energy Innovation Working Group

Submitted by:
The Benefit Cost Analysis Subgroup

Discussion Summary

- The BCA Subgroup recommends that the OEB develop a BCA framework to serve two purposes:
  - Decision-making purpose: the scope of BCA to be applied for decision making regarding distributor deployment of DERs in the alternative to traditional distribution system solutions.
  - Informational purpose: the scope of BCA analysis that it expects distributors to include in filings seeking approval for deployment of DERs in the alternative to traditional distribution system investments.
- The BCA Subgroup agreed that DERs present a broad range of potential benefits. The benefits and costs of DERs are often much broader than traditional distribution investments, and can include impacts to the whole energy system in addition to the distribution system.
- There was no consensus about the benefits and costs that the OEB should require distributors to apply in making the choice between DERs and traditional distribution solutions. The benefits and costs included in the test are the key elements of a framework that will determine how DERs compare to traditional distribution solutions, and the OEB must give guidance to distributors on which test should be used. There were many views, including:
  - Consider only the distribution benefits and costs.
  - Consider the benefits and costs affecting the implementing distributor's customers.
  - Consider the benefits and costs to the portions of the energy system to which the OEB can allocate, and from which the OEB can direct recovery of, costs.
  - Consider all energy system benefits and costs.
  - Consider all societal and energy system benefits and costs.
  - Consider the outputs of multiple views that examine the solutions from different perspectives.
- There were four primary factors influencing support for these views:
  - Overall cost-effectiveness and energy bill reductions;
  - Fairness in the distribution of benefits and costs;
  - The appropriate scope of costs to be included in distribution rates; and
  - The scope of the OEB's jurisdiction to allow for costs to follow benefits.
- There was majority agreement that, regardless of the scope of decision-making regarding DERs alternatives to traditional distribution solutions, the OEB should develop a BCA framework that includes the broad range of benefits, and costs, of DERs relative to traditional wires investments, as this would provide information on costs and benefits and how they accrue within Ontario's energy sector, and would thus inform policy development, regulatory, legislative or otherwise, in support of cost effective deployment of DERs in

Ontario. Majority support for this broad assessment was predicated on creating supporting documentation and tools to minimize the administrative burden on distributors when carrying out this broad analysis.

- Such a BCA framework would include the following components:
    - Purpose and use of the BCA.
    - The benefits and costs that should be considered.
    - The considerations for decision-making (i.e., the appropriate cost-effectiveness test).
    - Standardized BCA methods, assumptions, inputs, and tools to improve transparency and reduce administrative burden.
    - Standardized reporting requirements.
- There was also agreement that in order to facilitate deployment by distributors of DERs in the alternative to traditional distribution solutions, the OEB should:
    - Support the further development of standard assumptions, inputs, and methods for preparing a BCA as the work is not yet complete.
    - Explore and develop cost allocation methods to address distributional fairness.
    - Develop improvements to utility planning processes relating to DERs.

Contents

1. Introduction

This report is provided to the Framework for Energy Innovation Working Group ("FEIWG") from the Benefit-Cost Analysis ("BCA") subgroup (the "Subgroup"). The FEIWG was created by the Ontario Energy Board ("OEB") as described in its letter of March 23, 2021. The Subgroup was struck by the FEIWG to discuss and provide recommendations to the FEIWG about an approach to measure the benefits of using non-utility owned Distributed Energy Resources ("DER" or "DERs") relative to costs and assess the value of DERs relative to traditional distribution investments.[1]

This report captures the BCA Subgroup's discussions but does not reflect every Subgroup member's view on every topic. This report also does not reflect agreement among Subgroup members on every point, even where that is not explicitly stated.

The Subgroup's discussions uncovered a fundamental difference of opinion regarding the appropriate scope of considerations for decisions regarding DER and traditional solutions.

As a starting point, it was agreed that DERs may present a broad range of benefits. The benefits and costs of DERs are often much broader than traditional distribution investments, and can include impacts to the whole energy system in addition to the distribution system (i.e., capacity, energy, reliability improvements, avoided transmission, and potentially additional ancillary services).

One view is that where these energy system benefits, in aggregate, outweigh energy system costs, in aggregate, to create a net benefit that exceeds that of a similarly evaluated wires solution, then the OEB should approve deployment of that DER by the distributor, all other things equal. Failure to proceed with a DER where that is the case would be a lost opportunity, would be economically inefficient, and would ultimately result in higher electricity bills overall.

The other view was that the FEIWG's current mandate is to examine how DERs can be integrated into distribution system planning and operation, and that costs and benefits should, for decision making purposes in this context, be looked at primarily from the individual distribution system perspective and the DER should be deployed by the distributor where the distribution system benefits of doing so exceed the costs to the distributor's customers of doing so. While this approach might result in lost opportunities in respect of the broader (i.e., outside of the distribution system) benefits of a DER, capturing and securing those benefits is not a role for a distributor and should not be funded by distribution rates.[2]

Most of the Subgroup agreed on the value of a BCA framework that captures a broad range of DER benefits (and associated costs) and includes an assessment of the net energy system benefits to all ratepayers of the solutions being compared. Even under a narrower view of the role of Ontario distributors and OEB decision making in respect of deployment by Ontario distributors of DERs, it was agreed that a broad view of DER benefits can inform discussions

[1] The Subgroup's Terms of Reference is included as Appendix A. It sets out four tasks for the Subgroup that guided the Subgroup's discussion.

[2] A variation of this view is that where benefits to the deploying distributor's customers, whether through distribution rates or otherwise, outweigh the costs in distribution rates to the deploying distributor's customers, the DER should be deployed.

and decisions regarding additional DER benefits and how those can be captured and compensated to advance the cost-effective deployment of DERs.

In addition, if a distribution customer (vs. distribution system) test is to be used, it is necessary to determine overall energy system impacts to determine the impacts on a specific distributor's customers. For instance, if a DER will reduce provincial generation costs, that system-wide benefit would need to be calculated to determine the proportion of that benefit accruing to the distributor's customers.

The Subgroup has recognized that the broader nature of the potential DER impacts has two major considerations affecting a BCA framework for DERs:

- An analysis intended to holistically compare DERs and traditional distribution investments should consider the broader impacts to make a reasonable comparison of these alternatives and shed light on the investments that may be in the best overall interest of consumers and other stakeholders.

- At a minimum, this analysis would allow the OEB and other decision and policy makers to consider the distribution of these broad benefits among stakeholders in the energy sector and the implications thereof for the appropriate distribution of costs.

The Subgroup mostly agreed to pursue a framework that would allow for assessment of the broad range of benefits, and costs, of DERs relative to traditional wires investments, and further agreed to separately define and discuss the competing views on how this framework should be applied by the OEB in its decision making.

Section 2 summarizes the approach taken by the BCA Subgroup to evaluate the National Standard Practice Manual (NSPM)[3], presents the context under which those considerations could be applied in Ontario, and addresses why considerations of natural gas system implications have been deferred to the OEB IRP Technical Working Group[4].

Section 3 provides the catalogue of impacts that could be assessed for DERs, which some Subgroup members believe are relevant for informational purposes and other subgroup members believe should be relevant for decision-making. This list was developed based on the NSPM and the relevance of each impact to Ontario.

Section 4 discusses cost-effectiveness tests and reasons for the Subgroup's divergent views about which test the OEB should adopt.

Section 5 presents simplified examples of the outputs from a BCA to demonstrate the potentially different outcomes associated with different tests.

Section 6 summarizes the Subgroup's discussion about the methodologies and approaches to evaluating impacts.

Finally, Section 7 of the report identifies issues and future work that should be considered by the FEIWG and the OEB.

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[3] National Standard Practice Manual – NESP (nationalenergyscreeningproject.org).
[4] Natural Gas Integrated Resource Planning (IRP) | Ontario Energy Board (oeb.ca).

2. Subgroup Process, the NSPM and the Ontario Context

The Subgroup's Terms of Reference (TOR) established the objective for the Subgroup's work: "Defining an approach to measure the benefits of the DER use cases relative to costs and assess the value of DERs relative to traditional distribution investments." The FEIWG assigned four tasks to the Subgroup to achieve this objective:

1. Consider the applicability of the National Standard Practice Manual for Distributed Energy Resources (the "NSPM") for development of an Ontario specific BCA for DERs.[5]

2. Identify the types/categories of benefits and costs of the use case DERs alternatives to traditional solutions for meeting electricity distribution system needs.

3. Propose an approach/methodology to assessing these benefits and costs.

4. Propose how, if at all, each identified benefit/cost should be accounted for by distributors in choosing between non-utility owned DERs and traditional distribution investments.

This report develops a BCA approach that can be used by, among others, electricity distributors. Given the ongoing work by the OEB IRP Technical Working Group to look at developing a BCA or BCA framework for Ontario's natural gas distributors to consider DERs, there was little value in duplicating these efforts for natural gas distributors, and it is more appropriate for the IRP Technical Working Group to advance work for natural gas distributors, potentially informed by this work by the FEIWG.

2.1. Distribution Planning Context

The FEIWG and the Subgroup have been asked to develop an approach to measure benefits and costs of DERs relative to traditional distribution investments. This grounds the BCA within a distributor's planning process, and similarly grounds a BCA framework within the guidance provided by the OEB to distributors. The Subgroup mostly endorses a broad approach to assessing benefits and costs of DERs, as discussed elsewhere in this report, and proposes that with the appropriate tools to render the effort involved in such an assessment reasonable, such an approach is appropriate for distributors to use in evaluating DERs alternatives to traditional distribution system investment.

When a BCA is used to screen alternatives or make a proposal, it is important to recognize that cost-effectiveness is only one consideration within a distribution planning process. Planning decisions made by distributors, and the OEB's review of those decisions, are not informed solely by cost-effectiveness measured in a BCA. There are several other factors that are considered in the planning process and the BCA framework is not intended to override those other factors.[6]

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[5] National Energy Screening Project, *National Standard Practice Manual For Benefit-Cost Analysis of Distributed Energy Resources*, August, 2020 (http://www.nationalenergyscreeningproject.org/national-standard-practice-manual/).

[6] These factors include implementation (e.g., doubt around feasibility/performance, local opposition), qualitative considerations, future flexibility for uncertain needs (least regrets), and community preferences.

A BCA could be used for multiple purposes within the planning process. A BCA could be a high-level assessment of alternatives to determine whether a DER is likely to be a preferred option. A BCA could also be used to carry out a detailed assessment as part of a business case for a specific project to demonstrate that it is preferred to its alternatives. It could illustrate to stakeholders the advantages and disadvantages of DERs as compared to traditional distribution investments, or it could be used to establish a price cap for a competitive procurement of DERs to provide wires services.

The BCA framework described in this report relies on the planning process to define a need and to identify both DER and wires alternatives to meet that need. Once a need has been established and alternatives appropriately developed, the BCA framework will aid the distributor in carrying out a BCA.

2.2. NSPM

The NSPM was developed as a joint effort by a large number of leading energy policy experts across North America. The NSPM provides:

- A process and best practices for developing a BCA framework that is economically rational.
- Policy-neutral, technology-neutral, and objective guidance for developing BCA guidelines.[7]
- A process for arriving at a BCA framework that is tailored to a jurisdiction.
- Tools and support both for the development of a BCA framework and for the ongoing application of BCAs, such as guidance documents and case studies.

The NSPM does not direct a particular BCA. Rather, it provides a structured approach to determining the various BCA components and considerations relevant for evaluating the benefits and costs of DERs, and enables development of a particular BCA depending on the objectives of, and jurisdiction specific context for, the analysis being pursued. The Subgroup reviewed the BCA considerations described by the NSPM and discussed their applicability, relevance, and materiality to Ontario.

There is consensus that the NSPM has value for developing a jurisdiction-specific BCA framework. The NSPM's process, its catalogue of impacts and importance of consistent and transparent information are relevant to Ontario.

The NSPM highlighted that DERs can have broad impacts on the energy sector and society. The Subgroup agreed that there is value in assessing and reporting the energy system impacts of DERs because this will give all stakeholders a better understanding of the potential benefits and costs of the use of DERs to provide distribution services.

There was not a consensus on applying all of the NSPM's fundamental BCA principles and 5-step process in Ontario. The primary disagreement was whether all energy system impacts

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[7] National Energy Screening Project, *National Standard Practice Manual For Benefit-Cost Analysis of Distributed Energy Resources*, August, 2020 (http://www.nationalenergyscreeningproject.org/national-standard-practice-manual/), p. i.

should be included in the decision-making process for DERs when they provide distribution services. This disagreement conflicts with the NSPM's process, which requires that all energy system impacts should be included in a BCA for DERs. This disagreement is discussed in Section 4 regarding cost-effectiveness.

Despite some areas lacking consensus, the NSPM provided a good process and structure for the Subgroup's discussions. Attempting to define a BCA approach without using the NSPM as a reference would have been significantly more work, and important elements may have been missed. This starting point allowed the Subgroup to identify and delve into some of the Ontario-specific considerations that are relevant to the BCA framework. Leveraging a manual used in other jurisdictions where current and future tools will be developed also provides potential benefits.

2.3. Ontario Context

There is significant potential for DERs to provide cost-effective solutions to meet Ontario's electricity system needs, including distribution system needs. Almost all of the existing DERs are designed to provide a single service such as energy, rate mitigation, or local reliability.[8] There is a potential missed opportunity to use new and existing DERs to provide more than one service, which is how DERs can provide the most value to consumers and the energy system.

To date, few DERs have been developed to address location-specific distribution system needs, and these have mostly been targeted conservation and demand management programs.[9] There are potential opportunities to use existing DERs, and guide the siting of new DERs, to provide distribution services at a lower cost than traditional distribution investments.

Ontario does not have a single entity responsible for planning, procuring, and operating all electricity system services. Ontario has separate entities responsible for planning and operating distribution systems, the transmission system, and energy resources. There are also separate oversight processes for each of these services. Distributors and transmitters are regulated by the OEB. Resources can be regulated by the OEB, contracts and market rules or respond to rate incentives depending on the resource's technology, size, and location within the electricity system.

Ontario's electricity sector's structure adds complexity and coordination challenges for a DER that can provide multiple services to the electricity system. Consider an energy storage facility that seeks to reduce a customer's bill, provide distribution reliability services, and offer capacity to the IESO. The energy storage facility would need to enter into three separate agreements with a customer, the distributor, and the IESO, respectively.

The Subgroup agreed about the extent of this coordination problem but disagreed about how it should affect the design of a BCA for use by the OEB in evaluating distribution service

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[8] For example, Hydro One Networks Inc. is proposing to use energy storage for reliability but those resources likely will not provide other services. Similarly, the thousands of megawatts of FIT resources are not required to provide distribution or transmission service pursuant to the FIT or microFIT contracts.
[9] There have been examples of DERs deployed for distribution services, such as by PUC Distribution Inc., the York Region Pilot, and Toronto Hydro Electric System Ltd.

alternatives, if at all. These considerations for how cost-effectiveness would be assessed for the purposes of such decision making are discussed in Section 4 of the report.

Another unique aspect of Ontario is the wide range of distributor size, which will affect their respective capacities to assess and adopt DERs as alternatives to traditional distribution investments. Any BCA must be designed to support distributors with small planning departments and large planning departments alike. The Subgroup agreed that in the event of adoption of a broader (i.e., beyond the distribution system) BCA, whether for decision making or informational purposes, there is a need for clear OEB guidance and standardized tools to minimize the administrative burden of considering DERs in a distributor's planning process.

Another issue in Ontario is differing access to energy sources. Some electricity distributors may need to examine more fully DER alternatives inclusive of heat energy options (e.g., heat pumps). In addition, carbon pricing in Ontario may improve the cost-effectiveness of DERs relating to heat energy and align with municipal energy and emission plans.

Finally, Ontario has a complex policy setting environment. While the electricity system, for example, is a provincial jurisdiction, the federal government is setting climate objectives and clean energy policies that impact the sector. Municipalities also have a role that may influence distributor decisions. The policy challenges are most stark in the area of GHG emissions, and the policy influences shape the nature of societal impacts that might be considered through a BCA analysis.

2.4. BCA Framework for Electricity Distributors

The Subgroup found consensus that the OEB should establish a BCA framework that will guide electricity distributors when they carry out a BCA to evaluate the use of non-utility owned DERs used to provide distribution services in comparison to other solutions. The BCA framework should address two purposes:

1. The BCA framework should guide development of a BCA for use by distributors to evaluate DERs to traditional distribution investments. This requires that the OEB choose a cost-effectiveness test with guidance on which impacts are considered for decision-making purposes.
2. The BCA framework could more broadly inform stakeholders about the potential for DERs to provide a broader array of benefits to energy consumers in Ontario. This would require distributors to assess a broad set of impacts and report those impacts in situations where a DER is considered to meet an identified need.

The Subgroup recognizes the potential complexity and administrative burden of carrying out these BCAs, particularly the broader BCA, and particularly for smaller distributors. To address this concern, the BCA framework should also include standard methods, assumptions, and tools in support of achieving its determined purpose. Similarly, a standard reporting format will reduce the burden on stakeholders and the OEB when they review BCAs. To the extent that a distributor decides to deviate from that standard approach, they would need to justify the deviation in their application.

The Subgroup identified five components for a BCA framework:

1. **Purpose and use**: identifies when a BCA is required and the BCA's intended use (as described in section 2.1 above).
2. **Information requirements**: lists the impacts that should be considered for assessment in a BCA.
3. **Cost-effectiveness test**: sets out how the BCA impact assessments will be used to inform the decision on which solution should be deployed by the distributor all other planning considerations being equal. (section 4).
4. **Standardized methods**: provides standard methods, assumptions, and tools for carrying out assessments (section 6).
5. **Reporting requirements**: establishes the format for reporting BCAs (still to be developed under next steps).

3. Catalogue of Impacts

This section summarizes the candidate impacts considered by the Subgroup as potentially material to a BCA. The Subgroup used the impacts listed in the NSPM as a starting point. Each impact was reviewed for relevance in Ontario. The Subgroup has added additional impacts that have been raised in the FEIWG's discussions or the Subgroup's discussions.

Select impacts were also assessed to determine what energy service aspect(s) and other societal factors are impacted. For example, distribution losses occur on the distribution system but primarily impact resource costs. The definition and detailed implementation considerations have not yet been fully explored for all impacts.

The impacts presented in this section are separated between energy system impacts and societal impacts.

A separate issue of cost responsibility is addressed in Section 4.

3.1. Energy System Impacts

Table 3-1 below lists the energy system impacts considered by the Subgroup. The impacts have been mapped to service (distribution, transmission, resource and general). All impacts in Table 3-1 should be monetized when considered for inclusion in a BCA.

Table 3-1: Energy System Impacts

Impact	Description
Distribution Service Impacts	
Distribution Cost	Cost incurred by the distributor to obtain services from a third-party DER, including capital and O&M costs.
Distribution Capacity	Maintaining the availability of the distribution system to transport electricity safely and reliably.
Distribution O&M	Operating and maintaining the distribution system, program admin costs.
Distribution Ancillary Services	For example, service quality, reliability, harmonic control, frequency management, and reactive power management.
Risk	Uncertainty including as a minimum (a) execution risk (schedule & cost), (b) ongoing performance risk, and (c) risks that cannot be contracted for (force majeure, etc.) (See also "Planning Value" below.)
DER Host Impacts[10]	
Host DER Costs	Costs incurred by the DER host to install and operate DERs, including transaction costs & interconnection fees.
Risk	Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk may depend on the type of DER and Host.
Host Customer Non-Energy Impacts	Impacts of DERs other than direct energy and demand impacts, such as improved comfort or productivity arising from the DER.

[10] DER Host impacts are not an energy system impact but have been included in this table for simplicity. DER Host impacts can be included or excluded in an energy system approach as long as this is done symmetrically (i.e. both are included or both excluded).

Impact	Description
Transmission Service Impact	
Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably.
Risk	Uncertainty including as a minimum (a) execution risk (schedule & cost), (b) ongoing performance risk, and (c) risks that cannot be contracted for (force majeure, etc.) (See also “Planning Value” below.)
Resource Impacts	
Energy	The production or procurement of energy (kWh) from generation resources on behalf of customers, including the cost of environmental and other regulatory compliance.
Capacity	The generation capacity (kW) required to meet the forecasted system peak load.
Distribution System Losses	Electricity lost through the distribution system.
Transmission System Losses	Electricity lost through the transmission system.
Risk	Price risk and mitigation thereof (e.g. through energy efficiency).
Market Price Effects	The decrease (or increase) in wholesale market prices as a result of reduced (or increased) customer consumption. This can be difficult to calculate in Ontario due to the offsetting impacts of contracted and rate-regulated resources.
Ancillary Services	Services required to maintain electric grid stability and power quality.[11] For example, quality of service, reliability, harmonic control, frequency management, and reactive power management.
General Impacts	
Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components (utilities should specify whether it accrues to host customers or more broadly).
Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions (utilities should specify whether it accrues to host customers or more broadly).
Planning value	Option value in the planning process of facilities (e.g., shorter lead-times or facilities that can be redeployed, commitment period to asset, etc.).
Innovation and market transformation	This impact refers to potential future benefit streams arising from the development of an innovative energy resource or program or the development of a market for it.
Other Energy Systems Impacts	Impacts on other energy systems (gas, oil, propane, gasoline, water).

3.2. Societal Impacts

The Subgroup reviewed the non-energy system impacts (i.e., societal impacts) listed in the NSPM.

[11] See e.g. https://www.ieso.ca/ancillary-services

There was consensus that there could be value in knowing the full range of benefits and costs related to all options. There is disagreement on whether the OEB should require distributors to assess societal impacts for all such options.

The list provided in Table 3-2 below is intended to list potential societal impacts. The Subgroup recommends considering how these societal factors would be assessed as part of the future work for the FEIWG or the OEB. Many of the impacts in Table 3-2 do not necessarily need to be monetized and can instead be assessed qualitatively or with quantitative non-monetary figures.

Table 3-2: Societal Impacts

Impact	Description
Host Customer Non-Energy Impacts	Benefits and costs of DERs that are separate from energy-related impacts.
Economic development and jobs	Impacts on direct and indirect economic development and jobs.
Indigenous rights and reconciliation	Impacts on Indigenous rights and reconciliation, such as enabling indigenous communities to invest in DERs and accrue benefits from DERs (including as part of indigenous-owned utility).
GHG Emissions	GHG emissions created by fossil-fueled energy resources (beyond the monetized value of avoided GHG emissions which is already part of the economic analysis, including current and forecast values).
Other Environmental	Other air emissions, solid waste, land, water, and other impacts.
Public Health	Health impacts, medical costs, and productivity affected by health.
Low-Income	Reduced energy poverty, general poverty alleviation, environmental justice, and reduced home foreclosures.
Energy Security	Energy imports and energy independence.
Taxpayer	Government transfers, including incremental taxes (a potential cost) and grants (a potential benefit).

4. Measuring Cost-Effectiveness

Distributors need guidance on how the OEB will review the cost-effectiveness of DERs proposed to provide a distribution service and how cost recovery will be achieved.

If costs follow benefits, there are no concerns with how cost-effectiveness would be reviewed by the OEB. In this situation, the benefits relating to resource or transmission services would be paid by the ratepayers benefiting, and the social benefits would be paid by society. There would be no concerns about distributional fairness, price signals, or jurisdiction. The focus of the cost-effectiveness test would solely be on making the best decision possible by incorporating all impacts of the options being considered.

In reality, benefits do not always follow costs in Ontario and this is an obstacle to implementing DERs as described in section 2.[12] Including all energy system or societal benefits in a cost-effectiveness test adopted by the OEB or a distributor would mean that distribution ratepayers would potentially pay for the benefits of a DER through distribution rates based on benefits that do not exist within the distribution system or do not accrue to the implementing distributor's customers.

Given Ontario's current structure, the Subgroup members had divergent views on the appropriate breadth of impacts to include in evaluating the cost-effectiveness of deployment of DERs by distributors as alternatives to traditional electricity distribution infrastructure (for OEB approval of cost recovery in distribution rates). There were four considerations raised in discussing the impacts appropriately included in such an evaluation:

1. **Optimal decision-making** – There was agreement that recognizing in deployment decisions the broader impacts of DERs will lower overall energy system costs and energy bills and/or create greater societal benefits in comparison to other available options.
2. **Distributional fairness** – Costs and benefits could accrue unevenly among stakeholders and ratepayers in Ontario's electricity system. For example, it is arguably unfair for distribution ratepayers to pay for a DER to achieve broader benefits that do not accrue solely to those ratepayers. Ontario does not currently have mechanisms for allocating DER costs to those to whom the various types of DER benefits accrue.
3. **Distribution price signals** – Distribution rates are intended to reflect the cost of providing distribution services. These price signals are distorted by including DER costs for non-distribution services in distribution rates. Additionally, it was believed by some members that including DER costs for non-distribution services in distribution rates could circumvent the role of market forces in establishing price signals for other energy system benefits or for societal benefits at large.
4. **OEB jurisdiction** – Some Subgroup members felt that the OEB's jurisdiction could allow for costs to follow benefits within the OEB's jurisdiction (e.g., distribution, transmission, OPG prescribed assets and IESO fees). Other Subgroup members believed that this is

[12] See submissions to EB-2018-0287/0288.

an implementation concern and would potentially alter all cost-effectiveness tests equally and is not a reason to pick between one test or another.

Several cost-effectiveness tests[13] were developed and discussed to contrast the implications of the above considerations. These tests are presented in Table 4-1 below.

Table 4-1: Cost-Effectiveness Tests

Test	Perspective	Measure of cost-effectiveness
1. Distribution service	How the value of distribution service will change	A solution is preferred if it has the highest net benefits to distribution service as measured by changes to the value of distribution service (e.g., higher reliability) and the cost of distribution service.
2. Distribution customer	How distribution customers' total bill and value of service will change	A solution is preferred if it has the highest net benefits to the implementing LDC's customers based on changes to all energy system services received by those customers (both changes in value and changes in cost).
3. Regulated Utility Services[14]	How the OEB would allocate costs across the regulated system	A solution is preferred if it has the highest net benefits to the combined distribution and transmission system, potentially including other assets cost regulated by the OEB.
4. Energy system	How total energy system benefits and costs change	A solution is preferred if it has the highest net benefits to all energy customers in Ontario.
5. Societal	How total societal benefits and costs change	A solution is preferred if it results in the greatest net benefits to society overall.
6. Jurisdictional cost-test	How the impacts relevant to the jurisdiction change	A solution is preferred if it has the highest net benefits to customers under a test that is tailored to recognize the particular energy sector structure and other policies applicable in the specific jurisdiction (i.e. specific set of impacts that are relevant to the jurisdiction).
7. Multi-test	Assess multiple perspectives	A solution is preferred based on a consideration of multiple tests.

[13] There is debate about whether each of the above tests are true cost-effectiveness tests. One view is that a true cost effectiveness test should avoid conflating a determination of overall costs and benefits with consideration of the fairness of the distribution of those impacts. Under this view, cost-effectiveness would be calculated first and then distributional fairness (e.g., between the LDC's customers and other electricity customers) would be considered separately. Another view is that the test(s) for cost effectiveness should reflect the jurisdiction specific sector structure and legislative policy.

[14] Some subgroup members believe this is not feasible nor a true test of cost-effectiveness.

A major divergence among Subgroup members is exemplified by contrasting the distribution customer test and total energy system test. A focus on distribution customer impacts will lead a decision-maker to select a sub-optimal solution whenever a solution that results in the greatest energy system benefits entails a net cost for the implementing distributor's customers. If a solution achieves benefits for the customers of *other* distributors that cannot be recouped from those other customers, the two approaches can lead to different outcomes. This is significant because, for instance, the province-wide avoided generation capacity costs arising from reduced peak load are often greater than the avoided distribution system costs.

This divergence in outcomes between the two approaches arises only where costs do not follow benefits, such as an inability to allocate province-wide avoided generation capacity costs to all customers. There are generally two reasons why this arises:

1. **Market/regulatory structure:** Ontario does not have market or regulatory mechanisms to monetize all benefits or to ensure that costs always follow benefits. For example, there are significant timing and other limitations for resources participating in the IESO capacity markets. Similarly, there is no mechanism for the transmitter to contribute to projects primarily driven by distribution needs, let alone a mechanism that is timely. It may not be practical for a DER proponent to find a buyer for its services because of the multitude of procurement programs and significant participation gaps for certain technologies, such as energy efficiency, which cannot participate in the capacity auction or other long-term procurements.

2. **Inherent limitations:** Some DERs have prohibitive transactional costs or inherent externalities. For instance, the transaction costs necessary for costs to follow benefits can be prohibitive. For example, a solution that involves multiple DERs (e.g., storage, efficiency, and wires) may not be commercially viable if the contracting for each kind of benefit (e.g., energy, capacity, transmission, distribution) is too onerous and expensive. In addition, inherent to energy efficiency DERs is the accrual of avoided energy benefits primarily to the distribution customers who participate, rather than in reduction of distribution rates.

The likelihood of different outcomes between the distribution customer impact approach and the total energy system impact approach is heightened due to the features of Ontario's electricity sector. In particular, Ontario has many distributors and is not vertically integrated. Therefore, a distributor generally does not have the ability to allocate provincial benefits to provincial ratepayers. In contrast, a single vertically-integrated utility has much greater ability to allocate costs such that they follow benefits.

The Subgroup members agreed that efforts to create better mechanisms for costs to follow benefits should be expedited. Some efforts are already underway, including joint IESO/OEB work on cross-cutting issues; however, the Subgroup members disagreed on the decision-making guidance that should be provided (a) in the interim and (b) with respect to unresolvable situations where costs cannot follow benefits due to inherent features of the DER or intractable issues. As discussed in the following sections, the divergence in views stems in part from different views on how to resolve conflicts between overall cost-effectiveness, distributional fairness, and the appropriate role of distributors and the OEB.

4.1. Distribution Service Test

The distribution service test would evaluate the impacts associated with providing distribution service. A solution is preferred if it has the highest net benefits to distribution service. This includes the costs of distribution service (e.g., the cost to meet an identified need) and changes to the value of the distribution service (e.g., improvements in local reliability experienced by distribution customers). All other impacts are excluded from this test.

This test would evaluate the benefits and cost of distribution service change due to implementing the DER. A DER should be deployed by the distributor where the distribution system benefits exceed the costs of the service to those distribution customers and the net distribution system benefits outweigh those of the alternatives. Distributional fairness to the implementing LDC's customers is viewed as the limiting consideration.

This view also maintains price signals because distributors would only pursue DER options where distribution service costs decline or are justified by improvements to distribution service. No costs associated with other services would be considered nor included in distribution rates.

The main downside of this test is that it ignores the broader benefits of DERs and may reject DER projects that may otherwise create net benefits for the distributor's customers, all electricity customers, and/or society. Detractors would argue that adopting the distribution service test would mean:

- Sometimes selecting options that will result in higher energy bills for the distributor's customers by disregarding non-distribution-system benefits that would accrue to those customers (e.g. reduced distribution line losses or avoided energy costs);
- Effectively ruling out energy efficiency as a non-wires alternative as it is generally only cost effective when considering energy savings to the distributor's participating customers, which are excluded from a distribution rates approach;
- Effectively ruling out voltage regulation as a cost-effective DER as it is generally only cost-effective when considering energy savings to the distributor's customers (e.g. see EB-2020-0249); and
- Contradicting a "fundamental principle" and one of the five "steps" outlined in the NSPM.[15]

Supporters of this test would justify any potential missed opportunities by arguing that securing those benefits is not a role for a distributor and distribution ratepayers. In addition, supporters would argue that there is no conflict with the NSPM because the NSPM does not advocate for any specific test.

4.2. Distribution Customer Test

The distribution customer test would evaluate all energy system impacts to the implementing LDC's customers. A solution is preferred if it has the highest net benefits to the implementing LDC's customers. This includes the costs and value of all energy system services (distribution,

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[15] National Energy Screening Project, *National Standard Practice Manual For Benefit-Cost Analysis of Distributed Energy Resources*, August, 2020 (http://www.nationalenergyscreeningproject.org/national-standard-practice-manual/), pp. A-4 (limitations of this test), 2-6 (principle 5: incremental analysis), & 3-6 (step 2: include all utility system impacts).

transmission and resources). The provincial impacts accruing to other customers and societal impacts are excluded from this test.

In practice, this test would assign a portion of the provincial ratepayer impacts for transmission and resources to the implementing LDC's customers using a metric such as the proportion of peak demand or annual energy consumption. All energy system impacts on all ratepayers are calculated because they are necessary to determine the impacts on just the distributor's customers.

This test examines whether the implementing LDC's customers will be better off by implementing the DER. Net benefits relating to transmission and resources that can be attributed to the implementing LDC's customers may justify including additional DER costs in distribution rates.

The benefits of this test are that it broadens the impacts being considered and is more likely to result in implementation of DERs that achieve net benefits along this broader definition. This test also ensures that the implementing LDC's customers are better off, and therefore addresses distributional fairness.

The downside of this test is that it still excludes from the decision-making criteria many of the broader benefits of DERs that would accrue to provincial ratepayers and society. A decision that is optimal at the distribution customer level may be sub-optimal at the electricity system level or societal level. This test also fails to maintain price signals by potentially including costs associated with transmission or resources in distribution rates. Supporters of this test would emphasize the importance of distributional fairness as a reason not to consider the broader benefits that accrue to provincial ratepayers but a desire to facilitate more broadly cost effective DERs as a reason to compromise price fidelity.

4.3. Net Regulated Utility Test

Under this test, a solution is preferred if it has the highest net benefits to the combined distribution and transmission system, potentially including other assets cost regulated by the OEB. This test assumes that the OEB will consider the allocation of costs in accordance with benefits accruing across the regulated system.

Some Subgroup members believe that this test aligns with the OEB's capability to reallocate costs in accordance with benefits accruing across the regulated system. Others believe that the issue of cost allocation is distinct and can be addressed just as effectively regardless of the test that is chosen.

The advantages of this test are that it may include broader benefits than the distribution level tests while maintaining as prime consideration of distributional fairness in the decision-making process, and that it falls within the traditional role of the OEB to regulate.

However, some Subgroup members believe that this is not a feasible test. Some Subgroup members also raised concerns about whether the test is distinct or instead reflects separate implementation or policy issues associated with how benefits and costs are allocated among customers.

4.4. Energy System Test

An energy system test evaluates all the energy system impacts to all customers in Ontario. A solution is preferred if it results in the greatest net energy system benefits to energy customers overall. Typically, the preferred solution results in the lowest overall energy costs.[16] The focus is on all energy system impacts, including electricity distribution, transmission, and supply impacts. This aligns with two of the traditional cost-effectiveness tests, the "program administrator cost test" and the "total resource cost test," which are used to evaluate gas and electric energy efficiency programs in Ontario.[17]

This test determines whether provincial ratepayers as a whole will be better off by implementing the DER as opposed to the alternatives. Net benefits accruing to provincial ratepayers may justify including DER costs into the implementing LDC's rates even where the implementing LDC's customers are worse off.

The primary rationale for the energy system test is that it will promote solutions that lower overall electricity costs for Ontarians and provide experience and insight that could help reduce barriers to innovative non-traditional solutions that can lower electricity costs. In the coming decades, distributors will be more frequently assessing DER solutions against traditional solutions. If they pick the solution that lowers overall system costs in each case, Ontarians will be better off as a whole. The cumulative effect of many decisions that optimize overall system costs could result in lower prices to all Ontario electricity customers.

The main criticism of an energy system approach is that it can result in an unfair distribution of benefits and costs. The implementing LDC's customers can be worse off where they pay DER costs that create benefits that accrue to other customers. In contrast, supporters of this test argue that costs should follow benefits where possible, but where that is impossible, that should not rule out the solution that generates the lowest bills for customers overall. Uneven distribution of benefits or costs should be considered separately and resolved through mechanisms that do not involve continually picking a sub-optimal solution.

Supporters of this test also argue that distributional fairness should be evaluated across a portfolio of projects rather than on a case-by-case basis. They further suggest that if distributional unfairness persists at a portfolio level, mechanisms can be developed to compensate the implementing LDC's customers and transfer those costs to the provincial ratepayers who benefit from the DERs. Advocates point out that distributional fairness can be addressed through policy at a later date, but that constructing sub-optimal projects cannot be reversed until the asset is retired.

An additional criticism of an energy system impact test is that it will undermine price signals and ultimately slow or preclude the development of proper market prices and the economically optimal resource allocation and distributional fairness that results from properly developed markets. Supporters of an energy system approach respond that the energy system test does

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[16] However, the preferred solution may not result in the lowest overall energy costs when it results in non-monetary benefits that are deemed worthwhile, such as improved reliability.

[17] Both include energy system impacts, with the latter also including costs and non-energy benefits to the customers that implement the distributed energy resource (the "hosts" or "participants"). https://www.ieso.ca/-/media/Files/IESO/Document-Library/EMV/CDM_CE-TestGuide.ashx

not undermine markets as it does not preclude market/regulatory mechanisms from being used to allocate the relevant impacts. Further, an energy system test is also important where there are intractable market failures (e.g., excessive transaction costs) that rule out market mechanisms.

A further criticism of an energy system impacts test is that it may require the OEB and/or distributors to overstep their appropriate role and/or jurisdiction. If a solution performs services beyond supporting the distribution of electricity, can a distributor deploy that solution as a regulated business activity and can the OEB approve the recovery of associated costs in distribution rates? Supporters of an energy system impact test would argue that: (1) the OEB does not overstep its jurisdiction to ask distributors to account for costs in benefit-cost analyses even if those costs are managed by other entities (e.g., the IESO); and (2) distributors are not overstepping their role – they are simply considering the impacts of decisions between wires and non-wires solutions, and ignoring those impacts would be a decision to devalue them that would have ramifications for customers.

4.5. Societal Test

The societal test adds broader societal impacts to the energy system test. For a list of societal impacts, see table 3-2 above. A solution is preferred if it results in the greatest net benefits to society overall. This includes the costs and value of all energy system services (distribution, transmission, and resources) plus additional societal factors.

The advantage of the societal test is that it would select for projects that create the highest net benefits across all relevant impacts to society. This would lead to the most optimal decisions for society.

One drawback is that the implementing LDC's customers may be paying for benefits that accrue to society more generally, unless re-distributional mechanisms are deployed. This would harm distributional fairness and the price signals in distribution rates.

Another drawback is that broader societal impacts may be more challenging to calculate by LDCs and require expertise not contained in-house.

4.6. Jurisdiction-Specific Approach

Under a jurisdiction-specific approach, a regulator picks and chooses a set of impacts based on considerations specific to its jurisdiction and its approach to regulation, being careful to be symmetrical when accounting for benefit and cost categories. It can be thought of as a combination of the above approaches.

It is not necessary to simply "pick" one of the traditional tests of cost-effectiveness. There may be reasons for a jurisdiction to create their own. This is often done by adapting one or more of the traditional tests. However, one concern expressed is that defining and maintaining documentation related to cost effectiveness tests requires significant effort and resources, and if standard tests from the NSPM are not leveraged, the regulator would need to consider this issue.

For instance, a jurisdiction-specific test could include all energy system impacts and give utilities the option of including host customer cost and non-energy benefits depending on the situation. In relation to the Ontario context, this could address situations where a third-party DER provider would be disinclined to participate in a request for proposals where it would need to fully disclose all of its internal financial modelling. A jurisdiction-specific approach could also have Ontario-specific societal provisions to address greenhouse gas emissions and government transfers (i.e., taxes and grants).

4.7. Multi-test approach

Under this approach, a regulator asks the utility to calculate cost-effectiveness from multiple perspectives. For example, the IESO cost-effectiveness guide for conservation and demand management proposes that decision-making be based on all of the traditional tests. Electricity sector conservation and demand management is primarily evaluated using the total resource cost test. This includes all energy system costs as well as the costs and non-energy benefits to participants; however, the CDM guideline also recommends calculations using other tests to further inform decisions.

4.8. Implementation Considerations

Many, but not all, DERs will be able to earn revenues for transmission, resource, or societal benefits. Distributors will need to be able to identify the DERs that earn revenues from other sources in all tests except the Distribution Service test. This is necessary to ensure that the distributor does not consider benefits that are already accounted for through other processes. It also gives the distributor a better understanding of the DER's economics, and gives the distributor a better bargaining position when entering into agreements with DER developers, including under the Distribution Service test.

Concerns about optimal outcomes, distributional fairness, and price signals are addressed where the DER can realize revenues from other sources because the distributor no longer needs to compensate the DER for any of those benefits.

Where DERs cannot easily monetize broader benefits, there is an opportunity for the OEB to review the extent of its rate-making authority to improve the extent to which costs follow benefits. For example, the OEB could develop a mechanism for cost-sharing between transmitters and distributors where a DER provides both transmission and distribution benefits.

The Subgroup members agreed that the OEB should explore how, within its rate-making authority, it might create mechanisms to share costs beyond its current rate-making practices to seek to address the large proportion of the benefits of DERs that relate to resource services such as capacity and energy. Some efforts are already underway, including joint IESO/OEB work on cross-cutting issues.

It would also be beneficial to consider how to best coordinate procurements among distributors, transmitters, and the IESO to allow DERs to provide all services where it is feasible to do so. There is a significant risk that procurements for one service will interfere with a DER's capability to participate in another procurement. There may be opportunities within the context of regional planning to inform and/or facilitate such coordination.

4.9. Additional Considerations

Many Subgroup members agreed that LDCs should also consider factors beyond a comparison of net benefits according to the test chosen by the OEB where they are material to the comparison between solutions at hand. These additional considerations could include: (a) qualitative considerations, (b) quantitative non-monetized considerations, and (c) monetized impacts that fall outside of the calculation of net benefits, such as those outlined in Table 3-2. For instance, if the test chosen by the OEB excludes non-energy system societal impacts, those broader impacts could be considered separately from the cost-effectiveness comparison. In the very least, these factors can be used to break a tie between two otherwise equivalent solutions.

There was not consensus about how much weight to be put on these factors, whether they could be used to justify a solution that is not otherwise the most cost-effective, and the precise guidance the OEB should provide to utilities on these other considerations.

5. Examples

Examples help illustrate the different outcomes created by various tests and how impacts could be calculated.

The Subgroup developed three fictitious examples based on the use cases provided by ICF:

1. The first example looks at two options to meet a need for new distribution capacity to serve growing load. This example is similar to the use of DER Portfolio Approach in ICF's fifth use case.[18] The use case is intended to show a simple example of how BCA test options could lead to the same outcome.

2. The second example looks at two options to meet a need for new distribution capacity to serve growing load. This example is similar to the use of market-based DER aggregators in ICF's fourth use case.[19] The use case is intended to explore how existing DERs would be treated in a BCA.

3. The third example looks at two options to meet a distribution reliability need. This example involves a discretionary need and a "Do Nothing" option is also considered. This is similar to the use of electric vehicles in ICF's second use case.[20] This example shows that the inclusion of benefits flowing to all provincial ratepayers would change the preferred option.

The purpose of the case examples is to illustrate how possible tests may lead to different outcomes. The values and conclusions illustrated should not be interpreted as indicative of real-life scenarios.

5.1. Distribution capacity by new DERs

An LDC is experiencing rapid load growth in part of its service area due to housing and commercial development. The LDC forecasts that there will be insufficient distribution capacity to serve the growing load in the next 3 years. The distributor must reinforce its system to reliably serve the load and meet its obligations in its distribution licence (i.e., the need is non-discretionary).

The LDC has developed two options to meet the growing load. One option is to build new distribution lines to the area with growing load and the second option is seeking developers to build new DER in the area with growing load to defer the need for the new distribution lines by 4 years.

The impacts are as follows (all values net present value):

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[18] ICF, *Distribution Needs Cases /Additional Use Cases*, November 24, 2021, slide #10.
[19] ICF, *Distribution Needs Cases /Additional Use Cases*, November 24, 2021, slide #9.
[20] ICF, *Distribution Needs Cases /Additional Use Cases*, November 24, 2021, slide #7.
[21] ICF, *Distribution Needs Cases /Additional Use Cases*, November 24, 2021, slide #6.

- **Cost of distribution option**: $5 million for the distribution line.
- **Cost of DER option**: $4.5 million, consisting of $0.5 million for the DER plus $4 million for the deferred distribution line, which is less expensive on a net present value basis if it is deferred for 4 years.
- **Benefit of DER solution**: $0.1 million, consisting of the "option value" of the DER wherein the DER buys time, which may allow the LDC to find other, cheaper solutions or determine that the forecast load will not actually materialize.
- **Resource impacts**: The DER is expected to generate $10 million in resource benefits and cost $10 million to the IESO. One quarter of this benefit and cost would be charged to the implementing LDC's customers because they are roughly one quarter of the provincial load.
- **Distribution losses**: the options will likely have impacts on distribution losses, but these have been excluded for simplicity.
- **Societal**: the DER option is expected to achieve $0.2 million in societal benefits and the wires option is expected to achieve $0.1 million (e.g., fewer health and economic growth benefits).

The results of three tests are presented in the tables below.

Under the Distribution Customer Test, the DER proposal is preferred because it has a higher net benefit even though it has a negative benefit value.

Table 5-1: Example – Distribution Customer Test

(millions)	**New Dx**			**DER Proposal**		
	B	C	N	B	C	N
Distribution	$0	$5	-$5	$0.1	$4.5	-$4.4
Transmission	$0	$0	$0	$0	$0	$0
Resource	$0	$0	$0	$2.5	$2.5	$0
Total	$0	$5	-$5	$2.6	$7.0	-$4.4

Note 1: B – Benefit; C- Cost; N – Net Benefit.

The Energy System Test yields the same outcome because the transmission and resource benefits and costs cancel each other out again.

Table 5-2: Example – Energy System Test

(millions)	**New Dx**			**DER Proposal**		
	B	C	N	B	C	N
Distribution	$0	$5	-$5	$0.1	$4.5	-$4.4
Transmission	$0	$0	$0	$0	$0	$0
Resource	$0	$0	$0	$10	$10	$0
Total	$0	$5	-$5	$10.1	$14.5	-$4.4

Note 1: B – Benefit; C- Cost; N – Net Benefit.

The Societal Test yields the same outcome but with a stronger preference for the DER proposal due to the societal benefits created by the DER proposal.

Table 5-3: Example – Societal Test

(millions)	New Dx			DER Proposal		
	B	C	N	B	C	N
Distribution	$0	$5	-$5	$0.1	$4.5	-$4.4
Transmission	$0	$0	$0	$0	$0	$0
Resource	$0	$0	$0	$10	$10	$0
Societal	$0.1	$0	$0	$0.2	$0	$0.2
Total	$0.1	$5	-$4.9	$10.3	$14.5	-$4.2

Note 1: B – Benefit; C- Cost; N – Net Benefit.

5.2. Distribution capacity by existing DERs

A local distribution company is forecasting growing load in a constrained part of their distribution system. The distributor must reinforce its system to reliably serve the load and meet its obligations in its distribution licence (i.e., the need is non-discretionary). The distributor is considering using wires or DERs to meet the identified need.

The distributor has developed two options to meet the identified need. The first option is to build a new distribution line and reconductor another distribution line to provide the additional capacity needed to serve the growing load. The second option is using existing DERs managed by aggregators to defer the distribution investment by five years. These DERs would include existing demand response, behind-the-meter energy storage, and EVs with existing relationships with aggregators.

The impacts are as follows (all values net present value):

- **Cost of distribution option**: $15 million for the distribution line.
- **Cost of DER option**: $14.5 million, consisting of $3 million for upgrading the existing DERs to provide distribution capacity plus $11 million for the deferred distribution line, which is less expensive on a net present value basis if it is deferred for 5 years.
- **Benefit of DER solution**: $0.8 million, consisting of the "option value" of the DER wherein the DER buys time, which may allow the LDC to find other, cheaper solutions or determine that the forecast load will not actually materialize.
- **Distribution losses for the distribution option**: $0.8 million in reduced resource costs, which results in $1.6 million in reduced rates for the implementing LDC's customers because distribution losses are charged as a proportion of the total bill.
- **Distribution losses for the DER option**: $0.1 million in reduced resource costs, which results in $0.2 million in reduced rates for the implementing LDC's customers because distribution losses are charged as a proportion of the total bill. The DER has a lower impact on losses because the only change in behaviour from existing DERs is providing the capacity service for less than 20 hours per year.

The results of two tests are presented in the tables below.

Under the Distribution Customer Test, the distribution option is preferred because it results in a higher net benefit.

Table 5-4: Example – Distribution Customer Test

(millions)	New Dx			DER Aggregators		
	B	C	N	B	C	N
Distribution	$0	$15	-$15	$0	$14.5	-$14.5
Transmission	$0	$0	$0	$0	$0	$0
Resource	$1.6	$0	$1.6	$0.2	$0	$0.2
Total	$1.6	$15	-$13.4	$0.2	$14.5	-$14.3

Note 1: B – Benefit; C- Cost; N – Net Benefit.

The Energy System Test results in the same outcome because the distribution option is still preferred even when accounting for the true savings associated with distribution losses.

Table 5-5: Example – Energy System Test

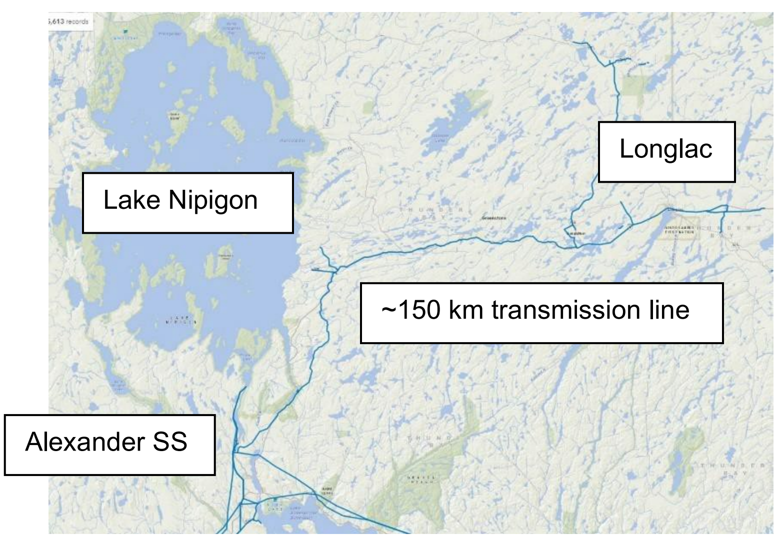
(millions)	New Dx			DER Aggregators		
	B	C	N	B	C	N
Distribution	$0	$15	-$15	$0	$14.5	-$14.5
Transmission	$0	$0	$0	$0	$0	$0
Resource	$0.8	$0	$0.8	$0.1	$0	$0.1
Total	$0	$15	-$14.2	$0.1	$14.5	-$14.4

Note 1: B – Benefit; C- Cost; N – Net Benefit.

5.3. Distribution reliability by new DERs

In this example, a rural community at the end of a long transmission line experiences poor reliability of service. The distributor is not required to improve the reliability of service to these customers, but the distributor is considering whether it can justify a discretionary project to improve the reliability of supply to the community. The discretionary nature of this reliability need means that a project must create a net benefit to be cost-effective.

Figure 5-1: Map of Rural Community



Source: https://data.ontario.ca/dataset/utility-line

The distributor has discussed reinforcing the transmission system to improve reliability, but it is not economically viable due to the high cost of twinning the long transmission line. The costs of the transmission line greatly outweigh the reliability benefits to the community.

The distributor considers procuring energy storage to improve reliability to the community. The DER developers explain that the energy storage facility would also be able to provide capacity and energy services, but that they're unsure whether they can earn revenues for those benefits.

The impacts are as follows (all values net present value):

- **Cost of wires option**: $90 million for the transmission line.
- **Cost of DER option**: $5 million for energy storage.
- **Resource benefits of DER solution**: $2 million in capacity and energy services. One quarter of these benefits are received by the implementing LDC's customers.
- **Transmission losses:** the options will have impacts on transmission losses, but these have little resource value due to transmission constraints and are therefore ignored in this example.

The results of two tests are presented in the tables below.

Under the Distribution Customer Test, neither the transmission line nor the energy storage facility pass the BCA because they create a net cost. The "Do Nothing" option is preferred.

Table 5-6: Example – Distribution Customer Test

(millions)	**Do Nothing**			**New Tx Line**			**Energy Storage**		
	B	C	N	B	C	N	B	C	N
Distribution	$0	$0	$0	$4	$90	-$86	$4	$5	-$1
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
Resource	$0	$0	$0	$0	$0	$0	$0.5	$0	$0.5
Total	$0	$0	$0	$4	$90	-$86	$4.5	$5	-$0.5

Note 1: B – Benefit; C- Cost; N – Net Benefit.
Note 2: the cost of the new transmission line would be allocated to the distributor as a connection asset.
Note 3: assume that distribution ratepayers are 25% of the system to determine the resource benefit.

The Energy System Test has a different result where the energy storage facility would pass the BCA because it creates a net benefit greater than zero. It is preferred to the "Do Nothing" option.

Table 5-7: Example – Energy System Test

(millions)	**Do Nothing**			**New Tx Line**			**Energy Storage**		
	B	C	N	B	C	N	B	C	N
Distribution	$0	$0	$0	$4	$90	-$86	$4	$5	-$1
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
Resource	$0	$0	$0	$0	$0	$0	$2	$0	$0
Total	$0	$0	$0	$4	$90	-$86	$6	$5	$1

Note 1: B – Benefit; C- Cost; N – Net Benefit.
Note 2: the cost of the new transmission line would be allocated to the distributor as a connection asset.

6. Methods

Impacts must be assessed in a consistent manner to support comparisons among alternatives. By establishing methods for assessing impacts, a BCA framework will ensure alternatives are compared fairly and also support consistent assessments across a distributor's projects and among distributors.

The Subgroup discussed the principles presented in the NSPM and has reached consensus in support of applying some of those principles to the development of methods in Ontario.

Further work is needed on these principles and developing specific methods based on the principles.

6.1. Difficult to quantify impacts

It is important to assess all impacts even where they cannot be easily quantified or monetized. While some impacts are difficult to quantify in monetary terms – either due to the nature of the impact or the lack of available information about the impacts – approximating hard-to-quantify impacts is preferable to assuming that the relevant benefits and costs do not exist or have no value.

6.2. Symmetric Treatment

Costs and benefits should be accounted for symmetrically in BCAs. Symmetrical treatment in the accounting of benefits and costs is necessary to avoid bias toward any one resource, whereby both benefits and costs are included (or both excluded) for each relevant type of impact.

6.3. No Double Counting

It is important to recognize the potential for overlap between some impacts to avoid counting any of them more than once. In particular, caution is required to ensure that costs included are not somehow captured in the benefits included, and vice versa. This is one reason why the BCA should provide detailed breakdowns of gross costs and benefits. Doing so will help all stakeholders see that double counting has not occurred.

6.4. Comparative Analysis

Cost-effectiveness should be measured by comparing the present value of net benefits for each project. The net benefits of a project are determined by taking the present value of gross benefits and subtracting the present value of gross costs over the study period. The Subgroup has not completed the work to define the basis of establishing the net present value.

The cost of a project should always be allocated to that project and not treated as an avoided cost that accrues as a benefit to other projects meeting the same need. A project could include enabling or foundational infrastructure.

The project with the highest net benefits is expected to be the more cost-effective project. Net benefits include qualitative impacts that cannot be easily quantified. All projects may have negative net benefits, in which case the most cost-effective project is still the highest figure (i.e., the "least negative"). For example, this may be the case for a non-discretionary need.

6.5. Study period

The study period should be based on the longest expected service life among the alternatives being considered. This is consistent with transmission planning practices. The Subgroup has not completed the work to define how varied lifetimes between alternatives be accommodated.

6.6. Incremental Analysis

BCAs should consider only incremental impacts, i.e., the changes that will occur because of the solution, relative to a scenario where the solution is not in place. This concept is applicable to both benefits and costs. The reference scenario should be identical for all the alternatives being compared and be informed by the specified need that the distributor is seeking to address. The Subgroup has not completed the work to define how the reference scenario and requirements would be articulated to enable comparisons of alternatives.

Similarly, LDCs should only include impacts that will materialize. For instance, if an LDC is accounting for capacity benefits, a mechanism must be in place to ensure that the capacity benefits will actually be realized.

6.7. Locational Analysis

The incremental analysis principle requires careful review of location for non-distribution impacts. The capability of a project to defer or avoid new infrastructure will depend on where the project is located. For example, a DER developed in a heavily-congested area of Ontario cannot defer or avoid resource costs because it can't contribute to meeting resource needs in other parts of Ontario due to the transmission congestion.

It will be important for the OEB to work with the IESO and transmitters to establish which areas of the province can realize capacity, energy, and transmission benefits.

However, in some cases it will be appropriate to use simplifying assumptions, as a fully detailed locational analysis may be onerous for a utility. Also, locational analysis may change as the electricity system evolves.

6.8. Transparency and Validation

The analysis must be transparent and allow for validation by the OEB and stakeholders. For instance, utilities should include the gross values for each impact included in the analysis, not only final results or net benefits figures. Also, sources should be indicated. A clear, transparent, and replicable approach is ideal.

As outlined in the section below regarding next steps, the Subgroup recommends that work be done to provide more guidance to utilities on cost and benefit inputs. This will assist in overall transparency and validation.

6.9. Materiality and Relevance

Calculating the full list of impacts for every project would create a large administrative burden on distributors who would need to carry out detailed assessments of potentially immaterial factors.

The BCA framework should provide distributors with flexibility along two dimensions. First, solutions can be screened out from further consideration using rough approximations to demonstrate that they are expected to be less cost-effective than other projects. Further work is needed to determine how distributors would screen projects (e.g., using optimistic assumptions or requiring detailed analysis if the BCA results are within a threshold). Second, distributors can exclude impact categories from the BCA where it can be demonstrated that the impacts would not apply to a DER project or would be immaterial. However, the Subgroup did not reach consensus on how materiality should be determined, whether it can be assessed on an impact-by-impact basis (e.g. where multiple small impacts may become material), and whether or how materiality should be balanced against the degree of effort required.

Excluded impacts should be documented and explained clearly.

Another important example of a DER that permits a simplified analysis is where the DER participates in the IESO-administered markets or other programs to internalize other benefits and costs. In these situations where a DER offers a distribution service at a set price, the distributor can potentially only consider the distribution benefits and costs of the DER project, in which case the DER would be analyzed in a similar way to a traditional wires investment.

7. Proposed Future Work

We recommend that the OEB take the following steps, to develop, implement, and support a BCA framework. The first item below is the critical first step and all other work could follow a commitment to developing a BCA framework.

- First, the BCA Subgroup recommends that the OEB develop a BCA framework to serve two purposes:
  - Decision-making purpose: the scope of BCA to be applied for decision making regarding distributor deployment of DERs in the alternative to traditional distribution system solutions.
  - Informational purpose: the scope of BCA analysis that it expects distributors to include in filings seeking approval for deployment of DERs in the alternative to traditional distribution system investments.
- Second, in accordance with such guidance, the OEB should develop further details for a BCA framework for use by distributors, including:
  - Ontario-specific standard assumptions, inputs, and methods for BCA analysis: To reduce distributors' administrative burden, promote consistency, and support accurate analysis of impacts, the BCA framework ultimately established by the OEB should include the following which require further development before finalizing, as applicable:
    - Avoided cost forecasts for generation (energy and capacity) which account for the unique structure of energy markets in Ontario, including the high proportion of costs included in the Global Adjustment;
    - An Ontario-specific approach to assess market price impacts of demand reductions;
    - Specific proxies, factors, or methodologies for the impacts to be accounted for in the BCA, focusing on the harder-to-quantify impacts;
    - Qualitative and non-energy system impacts;
    - The methods for informing the rate implications assessment of distributional fairness; calculating the NPV; and selecting a discount rate (e.g., inflation, societal, etc.) for summarizing the net benefits; and
    - Other standard assumptions, inputs, and methods as needed.
  - Reporting Template: The OEB should develop a reporting template which addresses both requirements for OEB approval requests and potentially broader DER impacts for information and future policy consideration. The NSPM has a template result reporting table that can be used as a reference point and starting place for Ontario's template, but it would require adaptation to be consistent with the Ontario context and the test(s) chosen by the OEB.
- Third, to support the adoption of NWAs that have net-benefits for Ontario consumers, the OEB should:

- Develop cost allocation mechanisms to address distributional fairness: The OEB should consider what tools it has within its jurisdiction to provide for compensation to an implementing distributor and its customers for non-distribution system DERs benefits accruing to customers at large (e.g., transmission rate adjustments to recover compensation to the implementing distributor for transmission benefits, compensation from the IESO to the implementing distributor to compensate for capacity or energy benefits from DERs where those benefits are supported by the IESO through a process such as Regional Planning).
- Utility Planning: Develop improvements to the utility planning process relating to DERs, including evolving the role of the regional planning process, the use of the BCA framework, and any recommended updates to OEB regulatory documents such as the filing guidelines, DSC, etc.

Appendix A – BCA Subgroup ToR

The FEIWG prepared Terms of Reference to govern the work of the Subgroup. Those Terms of Reference read as follows:

Objective: Defining an approach to measure the benefits of the DER use cases relative to costs and assess the value of DERs relative to traditional distribution investments.[22]

Approach: The BCA Subgroup will catalogue a broad set of benefits and costs for DERs alternatives to traditional solutions to meet distribution system needs and propose a BCA methodology to evaluate proposals by Ontario`s electricity distributors to adopt DERs alternatives to traditional distribution investments.

Tasks:

1. Consider the applicability of the *National Standard Practice Manual for Distributed Energy Resources* (NSPM (DERs)) for development of an Ontario specific BCA for DERs.

2. Identify the types/categories of benefits and costs of the use case DERs alternatives to traditional solutions for meeting electricity distribution system needs.

3. Propose an approach/methodology to assessing these benefits and costs.

4. Propose how, if at all, each identified benefit/cost should be accounted for by distributors in choosing between non-utility owned DERs and traditional distribution investments.

[22] FEI WG TOR, Appendix A, Workstream #1 – DER Usage, bullet 3.