Executive Summary

The PWU supports the Ontario Energy Board's (OEB) efforts to advance the Framework for Energy Innovation (FEI) as it relates to Distributed Energy Resources (DERs) and has been an observer in the FEI Working Group (FEIWG) proceedings since its inception. While the FEIWG significantly advanced the definition of the DER integration challenge and a Benefit Cost Analysis (BCA) framework for DERs, many questions, such as what are "*Ontario-specific assumptions, inputs and methods for a BCA?*" remain unanswered. [1]

As a result, the development of the BCA framework is not sufficiently advanced to assure that the lowest cost solutions for rate payers will result from the process. The PWU believes that a BCA framework should ensure the cost-effective adoption of DER technologies for **reliably meeting Ontario's emerging electricity system needs at the lowest cost to rate payers**.

This PWU supplemental submission provides additional comments to build on the recommendations of the FEIWG in order to help inform the OEB's choice of next steps for completing the BCA framework. This submission contains 20 recommendations across several themes:

- Integrate collaborative regional planning among the LDCs, transmitters and the IESO to establish requirements for cost-effectively meeting distributor needs with DERs
    1. OEB to define the relevant requirements in a "guidebook".
    2. A common BCA framework is applicable to both utility-owned and non-utility-owned DERs.
    3. Ensure affected stakeholders are engaged in the planning process.
    4. Develop a process to ensure validation of assumptions and implications.
    5. Develop a process to capture ongoing lessons learned.
- The definition of the initial conditions for a BCA should support a comprehensive and rigorous analysis
    6. Key assumptions should be traceable to publicly available planning documents.
    7. Definitions of the "Alternatives", their compliance requirements and their full costs should be transparently established.
    8. All options should be assessed over the same "lifetime" benchmark.
    9. A full analysis of the impact and potential reform of ancillary host incentives should be undertaken.
- Detailed integrated 8760-hour per year electricity system modelling should be used to assess:
    10. Energy impacts including losses and price impacts; and
    11. Capacity benefits.
- Incorporation of environmental attributes must be transparent and traceable
    12. OEB guidance on the applicable requirements should be provided.
- Characterizing the societal impacts of technologies would help facilitate the preparation of a BCA
    13. OEB should provide guidance and assumed values for GDP and tax implications, etc.
    14. The OEB should provide guidance on how the province's long-term energy security is being considered.

[1] FEIWG BCA Subgroup Report, June 2022, Page 33.

- Decision criteria for distributional fairness and rate setting among rate classes should be clarified
    15. BCAs should identify the regulatory premise for variances among rate classes.
    16. BCAs should identify impacts on different energy rate payers.
    17. A process should be established to inform ongoing rate program development.
- BCA outcomes must inform rate payers of the impacts on the key decision criteria
    18. Outputs should include forecast multi-year rate payer class cash flows, investment and operations cash flows typically used for and NPV calculation.
    19. The OEB should provide a template for reporting rate payer impact outcomes.
    20. The OEB should provide a template for summarizing assumptions and traceability.

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1. Introduction and Context

The PWU supports the Ontario Energy Board's (OEB) efforts to advance the Framework for Energy Innovation (FEI) as it relates to Distributed Energy Resources (DERs) and has been an observer in the FEI Working Group (FEIWG) proceedings since its inception. While the FEIWG significantly advanced the definition of the DER integration challenge and a Benefit Cost Analysis (BCA) framework for DERs, many questions, such as what are "*Ontario-specific assumptions, inputs and methods for a BCA?*" remain unanswered. [2]

As a result, the development of the BCA framework is not sufficiently advanced to assure that the lowest cost solutions for rate payers will result from the process. The PWU believes that a BCA framework should ensure the cost-effective adoption of DER technologies for **reliably meeting Ontario's emerging electricity system needs at the lowest cost to rate payers**.

The PWU submission provides additional comments and 20 more recommendations on the FEIWG subgroups' work[3] and is intended to help inform and accelerate the OEB's next steps for completing the BCA framework.

Accelerating the development of a BCA framework is becoming more urgent for several reasons:

1) The government recently issued a new letter of direction to the OEB emphasizing the need to accelerate efforts to reform the sector[4] → a BCA framework is a critical factor for transparently integrating the decision-making roles and responsibilities of Ontario's unique governance structure.
2) The OEB and the IESO are coordinating DER initiatives but are deploying different BCA methodologies.[5] → the FEIWG, IESO's regional NWA assessment and DER Potential Study.
3) It Is not clear what "*preparing for a high DER penetration*" entails → specifically how it may relate to Behind the Meter (BTM) demand side management (DSM) opportunities versus the adoption of distributed generation e.g., solar. The BCA methodology used in the DER Potential Study conflates these questions.[6]
4) Ontario has a supply crisis and determining the most cost-effective role of DER relates to Ontario's expected demand growth and the supply mix procured to meet it → the methodology used in the DER Potential Study is inadequately informed with results not useful for decision-making.[7]
5) The government wants to take action to secure the environmental and economic benefits of the transformation and ensure investments are made in the interests of rate payers[8] → These criteria will necessarily influence the nature of the BCA framework.

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[2] FEIWG BCA Subgroup Report, June 2022, Page 33.
[3] PWU submission to the OEB on the FEIWG reports, Sept 2, 2022.
[4] Letter of Direction from the Minister of Energy to the OEB, October 21, 2022.
[5] The IESO 's BCA methodology used for its Non-Wires Alternatives (NWA) assessments in regional planning is different from the FEIWG's identified considerations for a BCA framework and the BCA methodology deployed in development of the DER Potential Study for the IESO used an altogether different approach.
[6] PWU submission to the IESO on the DER Potential Study report, October 28, 2022.
[7] PWU submission to the IESO on the DER Potential Study report, October 28, 2022
[8] Letter of Direction from the Minister of Energy to the OEB, October 21, 2022.

The PWU believes that an established and common BCA framework to inform investment, procurement, and rate program decisions across Ontario's energy sector is critical for a successful energy transition that reliably meets the province's electricity needs at the lowest cost to rate payers.

Context for Analysis

The FEIWG report emphasized the need for sound and robust evidence-based policy.[9] The FEIWG DER Integration (DERI) subgroup report identified that changes to the existing regulatory and governance framework may be required in four areas:[10]

a) Collaborative planning across all levels to establish requirements and solutions;
b) The provision of information for both planning and operating purposes;
c) A method for ascertaining when DERs are a cost-effective alternative for meeting system needs;
d) Mechanisms for the electricity sector to recover the costs of DER solutions.

The FEIWG BCA subgroup identified that a BCA should be the method used to address item (c) above and identified the need for "*a BCA framework that includes the broad range of benefits, and costs*."[11] The subgroup recognized that more work remained to define the implementation details, including how to determine the underlying assumptions. Specifically, the BCA subgroup report identified several areas requiring additional work, including: [12]

- The standard assumptions, inputs, and methods for preparing a BCA;
- A template for standardized reporting;
- Methods for informing the rate implications assessments, calculating the Net Present Value (NPV), and selecting the discount rate; and
- Improvements to utility planning processes relating to DERs.

Thus PWU puts forth several important considerations that should be considered in the next steps to develop a BCA:

- Ensuring that a comprehensive, integrated approach is taken to address the evident, aforenoted issues. This is the best way to demonstrate that the government's energy transition objectives are being met;
- Providing consumers with transparent, evidence-based information that ensures that decisions build to a least-cost electricity system that sustains the reliability consumers expect; and,
- Defining the required "transparency" standards for the information required to support DER-related decisions, specifically the origin of these costs and their subsequent impacts on rate payers.

Structure of Report

The report has been structured as follows.

[9] FEIWG Final Report, June 2022, page 6.
[10] FEIWG DERI Subgroup Report, June 2022, pages 4, 5.
[11] FEIWG BCA Subgroup Report, June 2022, page 2.
[12] FEIWG BCA Subgroup Report, June 2022, pages 3 and 33.

Section 2.0 Role of the BCA in Planning and Decision Making examines the development of the BCA framework within the context of a collaboratively-developed, integrated, energy system plan for Ontario. It describes: Ontario's current multi-stakeholder planning environment; the role of the BCA in planning and procurement decision-making; the impacts on the BCA framework; and, recommends a more holistic process.

Section 3.0 Initial Cost Conditions of a Comparative BCA presents the consideration for conducting BCAs that compare alternatives: on a level playing field of equivalent requirements; accounting for asset lifetimes; and, includes additional host impacts when non-utility owned DERs are options.

Section 4.0 Characteristics of Cost and Benefit Impacts Critical for Decision Making addresses factors that can materially alter outcomes of a BCA: the fidelity of the electricity system modeling for impacts on both energy and capacity; the appropriate reference for considering environmental factors; and, the characteristics of the inputs required to address the societal factors of jobs, GDP and competitiveness that the government is currently expecting the OEB to consider.[13]

Section 5.0 Foundational Methods for Analysis looks at the appropriate use of NPV and the relevance of societal discount factors, given that the OEB's primary objective should be to ensure the lowest cost for rate payers while meeting the electricity system's reliability needs set by the planning process. By comparison, assessing the financial return on an investment is not the same objective.

Section 6.0 Standardized Outputs and Confirming Option Selection discusses the standardized format of the BCA outputs as required to assess the impacts on rate payers and other stakeholders, support assumption and outcome validation and inform decision making with respect to option selection and cost recovery.

[13] Letter of Direction from the Minister of Energy to the OEB, October 21, 2022.

2. Role of the BCA in Planning and Decision Making

This section examines the development of the BCA framework within the context of a collaboratively developed, integrated, energy system plan for Ontario. It describes: Ontario's current multi-stakeholder planning environment; the role of the BCA in planning and procurement decision-making; the impacts on the BCA framework; and, recommends a more holistic process.

The need for integrated planning

Initially, the FEIWG was asked to examine how local distribution companies (LDCs) could utilize non-utility owned Distributed Energy Resources (DERs). During the FEIWG discussions, it became apparent that the benefit and cost impacts of DER extend beyond those of location and ownership. The impacts may extend to the entire electricity system – customers, distributors, transmitters, bulk system generators and market operations—and broader societal benefits in support of government policy objectives. The FEIWG BCA subgroup defined relevant costs and benefits impacts to form the basis for conducting a BCA of rate payer impacts as summarized in Table 1.[14]

Table 1 – Mapping of BCA Elements to Sector Stakeholders

BCA SG Report Category	BCA Impacts	Ontario Sector Stakeholder	Oversight Process
Distribution	Cost, capacity, O&M, ancillary services, risk	Distribution Co	OEB
Transmission	System availability*, risk	Transmission Co	OEB
Resources	Energy and generation capacity, impacts of Tx/Dx losses, risks	Generation- regulated	OEB
		Generation- unregulated	IESO
	Bulk System Operation	System operation (IESO)	OEB (IESO budget)
	Market Price effects, Ancillary services		IESO
General	Reliability, risks, resilience, planning value		IESO
	Other energy system impacts	e.g. Natural Gas Distr.	OEB
	Innovation and transformation,	Not yet determined	
Societal	GHG emissions, GDP and jobs, Energy Security, Indigenous peoples	Society	Government, TBD
	Taxpayer		
	Other environmental, public health, low income supports		

* Tx availability elements for BCA consideration are the same as for the distribution system, i.e. Cost, capacity, O&M, ancillary services.
Note: The host impacts are considered in Section 3(d).

The FEIWG BCA report identified that "*Ontario's unique electricity sector's structure adds complexity and coordination challenges for DERs*. … *Ontario does not have a single entity responsible for planning, procuring, and operating all electricity system services. Ontario has separate entities responsible for*

[14] FEIWG BCA Report, June 2022, pages 13-15

planning and operating distribution systems, the transmission system, and energy resources."[15] There are also "*separate oversight processes such as regulation by the OEB and contracts and market rules by the IESO*". The relationship of the BCA elements to Ontario's electricity sector structure and oversight processes is directionally indicated in Table 1.

Capacity values for both generation and transmission are generally viewed as the greatest contribution to DER value.[16] The IESO's recently commissioned DER Potential Study report identified that generation and transmission capacity avoidance/deferment value accounted for 80% of the identified DER benefits.[17]

DERs by definition are distribution connected and the FEIWG focused on how LDCs would approach option selection decisions. However, this sets up a "conflict of interests – LDC versus transmitter investment decisions for grid capacity versus IESO procurement decisions for grid connected resources—with the lead planner being the IESO. As part of its regional planning activities, the IESO is evaluating non-wires alternatives (NWAs) and making determinations, generally in favor of wires solutions.[18] Some of these decisions may obviate the benefits of subsequent DER options for LDCs. Integrated planning would ensure that consistent planning decisions are made amongst the LDCs, the IESO and transmitters and also avoid the potential for the "double counting" of benefits from uncoordinated, independent investment choices made by the respective parties. As the BCA subgroup noted, double counting of benefits should be avoided.[19]

Integrating Ontario's Planning and Decision-Making and the Role of the BCA Framework

The DERI subgroup determined that a framework for innovation that effectively plans for the best use of DERs in a lowest cost, reliable electricity system should include:[20]

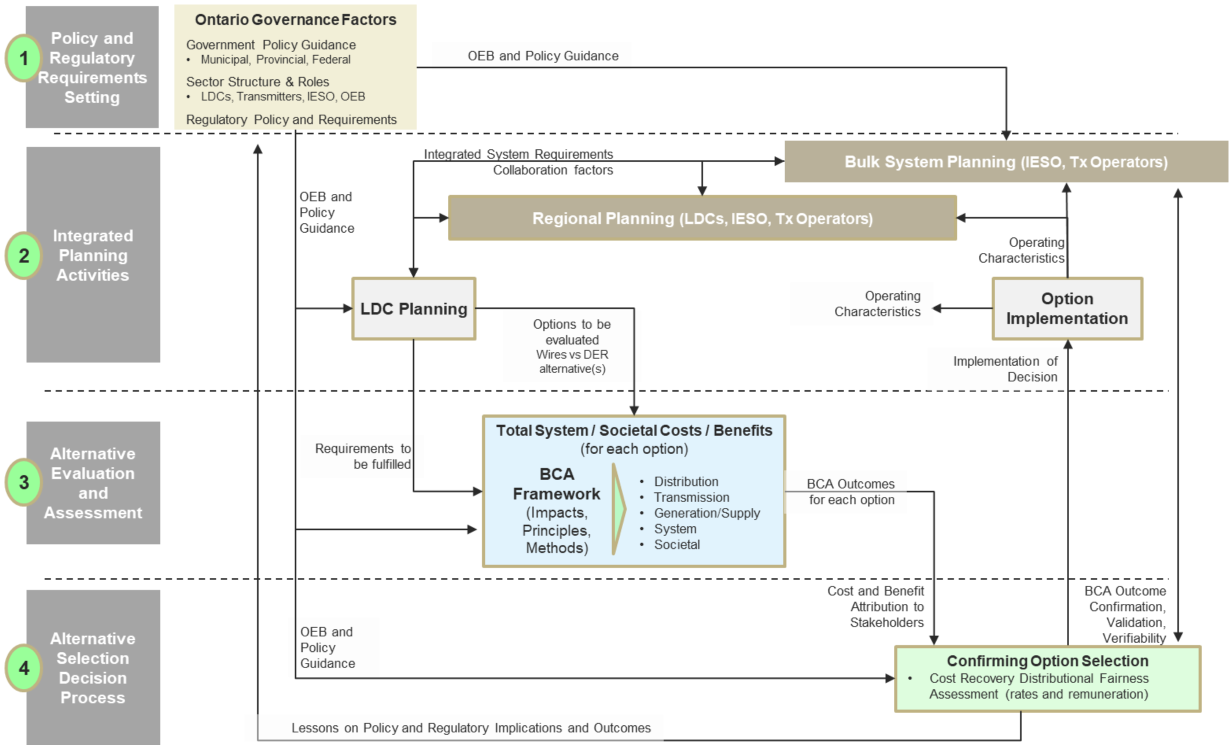
- Integrated planning at all levels; with the provision of information for both planning and operating purposes;
- A method for ascertaining when DERs are a cost-effective alternative for meeting the needs of the utilities; and
- A mechanism for recovering the costs of beneficial investments, including utility remuneration practices.

A framework that captures these DERI-identified priorities is illustrated in Figure 1. It consists of four groups of activities, including the need to address the compliance requirements for LDC options:

1. Policy and Regulatory Requirements Setting
2. Integrated Planning Activities
3. Alternative Evaluation and Assessment
4. Alternative Selection Decision Process

[15] FEIWG BCA Report, June 2022, page 10.
[16] FEIWG BCA Report, June 2022, page 18.
[17] IESO DER Potential Study report, Oct 2022, page 64 for the middle scenario "BAU+".
[18] Recent IESO regional planning webinar materials for Renfrew, Gatineau, Northwest, etc. Oct/Nov 2022.
[19] FEIWG BCA Report, June 2022, page 30, section 6.3.
[20] FEIWG DERI Subgroup Report, June 2022, pages 4, 5.

Figure 1 – LDC DER-related Decision-making Process and Validation Needs



Each of these activities represent critical steps to ensure that: cost-effective DER investment decisions are undertaken; checks and balances are implemented for validating assumptions; appropriate recovery of those investments is realized by affected parties; and, operational data feedback to the planning process is in place. Each activity includes key features, process communications, and feedback loops that support the overall efficacy of the framework.

1. Policy and Regulatory Requirements Setting

   Currently, the integration of DERs into Ontario's electricity system is being shaped by: government policies, at all levels; the sector structure and the roles of the decision-making stakeholders; and, the regulatory policies and requirements established by the OEB.

   Provincial government policies include the legislative acts that dictate the roles and responsibilities of the stakeholders, such as the *Electricity Act* and *OEB Act* and various directives to its crown agencies and corporations e.g., the OEB and IESO. The federal government has jurisdiction on requirements associated with interjurisdictional interfaces and the North American reliability standards established by the North American Electricity Reliability Corporation (NERC). Some societal matters have overlapping provincial and federal policies, such as with the Provincial Emissions Performance Standard (EPS) and the evolving Federal policies for Carbon Price, Output-Based Pricing System and Clean Electricity Regulation (CER).

Municipalities may have additional policies governing their local distribution companies or provide council resolutions with respect to the types of electricity generation to be constructed in their jurisdictions.[21]

The OEB sets the regulatory requirements for the province including electricity performance requirements such as those set by the Distribution System Code and related regulations.

Each of these government policies and regulatory drivers impact on the other four activities in Figure 1. These include the individual planning activities of the sector stakeholders, the key requirements to be considered in the BCA, and drivers of DER decision outcomes. An effective BCA framework will require clear, transparent, consistent application of the DER decision-making requirements across all of these activities.

Implementation of the BCA may require new policies e.g., for remuneration and rate setting practices, connections processes and costs, etc. The OEB may choose to provide latitude for local decision-making priorities.[22]

> ***Recommendation #1:*** The OEB should compile the relevant guidance and clearly specify requirements in support of DER decision making. This could be in the form of a DER Evaluation handbook, user guide or some equivalent tool to be determined by the OEB.[23]

2. Integrated Planning Activities

Ontario's electricity planning occurs on three levels: the bulk system led by the IESO and the Tx operators (e.g. Hydro One); regional planning led by the IESO in collaboration with the LDCs and local stakeholders; and, at the local level by the LDCs. As illustrated in Figure 1, these planning activities are influenced by OEB and provincial policy guidance.

For LDCs to make optimal decisions regarding DERs requires integrated collaboration and information sharing within the regional planning and bulk system planning processes. Since many DER benefits accrue to the overall system, a mechanism is required to articulate the relevant integrated system requirements for an LDC. As the DERI subgroup noted, the planning process must also be informed of the presence and operation of existing DERs as they may impact on both the requirements and for LDC option identification.

The purpose of the planning activities, in the context of DER integration, is to establish the LDC's needs, specifically the requirements that potential wires and NWA options must meet. These options could be traditional infrastructure, a single DER, a group of DERs and or a combination of DERs and traditional infrastructure.

> ***Recommendation #2:*** While the FEIWG focused only on non-utility-owned DERs, this framework would apply to both utility-owned and non-utility-owned DER options that may

[21] Many municipalities have passed motions prohibiting new gas fired generation or are concerned with new wind generation.
[22] OEB Bulletin, Local Community Preference for Alternative to most Cost-Effective Solution, Sept 28, 2022.
[23] This is a corollary to the FEIWG recommendation to create industry tool sets.

feasibly meet the requirements. There is no need from an evaluation perspective to distinguish the two.

The planning exercise should define the needs of the LDCs in terms of the characterizing requirements against which the LDC can assess both wires and DER options for cost effectiveness. These requirements would form the basis of the alternative evaluation and assessment activities – the focus of the BCA.

An important element of integrated planning is the confirmation, validation and verification of the BCA outcomes by affected stakeholders, including the underlying assumptions and inclusion of the benefits of DERs in subsequent planning cycles for the regional and bulk systems. This helps ensure that the identified benefits of DER integration are captured and not double counted.

> ***Recommendation #3***: The OEB should ensure that the stakeholders in affected regional and bulk system planning are engaged in the OEB-determined Option Selection process for approving LDC investments in DERs.

Specific recommendations on how the Option comparison should be setup for evaluation is discussed in Section 3.

3. Alternative Evaluation and Assessment

The primary purpose of the FEIWG's development of a Benefit Cost Analysis (BCA) framework is to support the evaluation and assessment of DER alternatives to wires solutions. The FEIWG BCA subgroup advanced the development of relevant considerations including the elements to be considered, as summarized in Table 1, as well as the principles and methods that should be deployed.[24] BCAs should provide a rational, transparent, verifiable and deterministic method for determining the net benefits of compared options on an equivalent basis by decision makers.[25]

However, it was recognized that further details for Ontario-specific standard assumptions, inputs, and methods for a BCA analysis remain to be defined.

Section 4 discusses the assessment of selected Ontario-specific considerations that the PWU deems critical to the outcomes of any BCA. Section 5 discusses important considerations in the applied methods in order to minimize the rate payer cost impacts of available alternatives.

The BCA framework is intended to make benefit cost assessments more economically rational, transparent and consistent to help assist the OEB, utilities and stakeholders with planning, decision-making, communication and adjudication. As such, defining the form of the outputs from a BCA analysis should consider these multiple objectives in support of the next step in the process – decision making for the selection of alternatives. A critical outcome from a BCA is a clear, transparent articulation of the assumptions, costs, and benefits impacts that can be attributed to each stakeholder in Ontario's electricity sector structure. This fidelity is critical to validating the

[24] FEIWG BCA Subgroup report, June 2022, section 6, pages 30-32.
[25] Principles identified by the FEIWG BCA subgroup report, June 2022, Section 6.8, page 31.

reasonableness of the benefits assumed to be realized by those affected stakeholders.[26] This stakeholder confirmation would underpin any OEB assessment of distributional fairness.

A proposed format for the BCA outcomes is provided in Section 6.

4. Alternative Selection Decision Process

The last stage in the process confirms the options that will be selected. There will be three decisions that the BCA outcomes should inform.

a. Which option has the greatest net benefits to rate payers?
b. Is there a reasonable distribution of expected cost and benefits among stakeholders?
c. Can the costs and benefits be fairly distributed among affected stakeholders?

The BCA outcomes should definitively identify the net benefits of each option for each stakeholder and ultimately for rate payers. As mentioned above, the BCA assumptions and outcomes require validation by affected stakeholders. This validation should ultimately be extended to reflect the integration and realized benefits for the bulk and regional planning processes. The BCA subgroup report stated that only impacts that are expected to materialize should be included.[27]

> ***Recommendation #4:*** A process by which affected stakeholders can validate and verify the assumptions and implications of NWAs must be developed. This could be addressed in several ways: improvements to the regional planning process as recommended by the BCA subgroup i.e., checks and balances; Intervenors acting on behalf of the affected stakeholders in the rate hearings; and/or, guidelines and assumptions from the OEB.

The last question focuses on the OEB's role in the decision-making process. The BCA subgroup report addressed the many considerations involved in assessing distributional fairness. The BCA subgroup report also recommended that the OEB consider what jurisdiction it has with respect to cost recovery and benefit sharing among affected stakeholders. [28]

> ***Recommendation #5***: A continuous improvement feedback loop that captures the lessons learned from the BCA framework should be developed to inform Policy and OEB guidance going forward.

[26] FEIWG BCA subgroup report, June 2022, page 31, states only benefits, that will actually be realized should be included and supported by an appropriate mechanism
[27] FEIWG BCA subgroup report, section 6.6, page 31.
[28] FEIWG BCA subgroup report, June 2022, page 34

3. Setting Initial Cost Conditions for a Comparative BCA

The BCA subgroup recommended that the BCA should be conducted as a comparative analysis.[29] This section presents four considerations for ensuring that a BCA provides a fair and objective comparison of alternatives.

- Establishing the requirements for all options
- Aligning asset lifetimes
- Delineating the direct costs of the options
- Additional considerations for non-utility owned DER options.

a) Requirements define the objective basis of a comparable analysis

As described in Section 2, a consistent and common set of technical requirements that must be fully satisfied by all the options, is the first essential component of a comparative BCA.

Government and OEB policy requirements would be standard, commonly identified and be applicable for all technical solutions that meet the needs of an LDC. Specifications, codes and standards include the DSC, CSA standards, and the DER connections requirements.

The BCA subgroup recommended that the analysis be completed on an incremental basis with respect to a reference scenario that is identical for all alternatives.[30] This is driven by the specific needs to be addressed by the collaborative system planning activities described in Section 2. The reference scenario would therefore be the status quo planning reference used in planning and against which the planners have identified an investment need.

The unique requirements would be those that have specifically emerged from the planning exercises, the most common of which is the need for capacity expansion, but could also include other performance requirements like voltage stability, etc. The compared options must all be fully compliant with the associated requirements for meeting system needs.

> **Recommendation #6:** Validation and investment decision-making requires being able to trace the requirements outlined in the planning documents e.g., the APO, AAR, energy and regionally determined capacity needs from the regional planning process and LDC planning documentation. This traceability is important for enabling all stakeholders to understand the respective options in play i.e., at the bulk, regional and LDC levels. The preceding validation of the requirements ensures that the BCA assumptions remain relevant.

b) Delineating the direct costs of the options under consideration is the essential first step

The options available to an LDC should be clearly defined and supported by a rational description of the requirements/needs that will be met by each option. Alternative options could consist of wires solutions, a DER non-wires solution or solutions, or some combination. If a DER solution does not completely meet a need, then a hybrid solution may warrant consideration.

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[29] FEIWG BCA subgroup report, June 2022, page 16, examples in section 5, section 6.4, page 30 (although basis for comparison is not resolved).

[30] FEIWG BCA subgroup report, section 6.6, page 31.

The BCA should start with an expression of the direct costs of implementing the alternatives, the explicit purpose being to identify those costs that will be recovered from rate payers. Table 2 summarizes the capital investment, as well as the operation and maintenance (O&M) costs that should be identified for each case. Hybrid solutions will likely have cost components similar to those for the wires and DER solutions, although with some variability in magnitude.

Table 2 - Summary of Direct Costs for Use in a BCA Comparable Assessment

Source of Costs	Wires solution	DER Solution	Hybrid Solution
Conventional LDC Costs	Transformers/wires capital LDC Incremental O&M Mid-life refurbishment or upgrade (e.g. transformer)	LDC portion of connection costs LDC DER Integration O&M costs	Transformers/wires capital LDC Incremental O&M Mid-life refurbishment or upgrade (e.g. transformer) LDC portion of connection costs LDC DER Integration O&M costs
DER Technology Solution Costs		Equip capital & Installation Connection costs O&M Costs Mid-life refurbishment or upgrade	Equip capital & Installation Connection costs O&M Costs Mid-life refurbishment or upgrade

Notes: O&M includes both fixed and variable costs; Integration costs could include some portion of DER Integration enabling infrastructure costs

Additional equipment should be identified, particularly for DER solutions. These include:

- Connection costs
    - There are additional costs associated with connecting some DERs to the distribution system grid. These costs result from: the LDC portion of connection costs that would be incurred by an LDC and not directly allocated to a DER installation; and, the connection costs attributable to the installation. This generic distinction should be applied equally to LDC or non-LDC owned DERs.
    - The DER connections process defines how these costs are determined for third party owned DERs. For third party owned DERs, the costs of connecting a DER is generally paid for by the entity requesting the connection, as defined by the DER connections process. A proxy of those costs incurred by an LDC for LDC-owned DERs would be included as part of the DER Technology costs.
    - Nevertheless, there may be additional costs incurred by the LDC that would not be recoverable from a third party, such as transaction costs, which may arise for both utility and non-utility owned DERs.
- LDC DER Integration
    - LDC DER integration costs, for both the capital and O&M elements, are required to operate the installation e.g., the dispatch process. The DERI subgroup concluded that the OEB should define how the costs of enabling infrastructure, e.g., for monitoring and control should be authorized and recovered.[31] This cost element would include the incremental costs for adding a DER, but could also include an allocated amount of the overall infrastructure, depending on the policy that the OEB selects.
- Potential mid-life refurbishment or upgrade costs

[31] FEIWG DERI subgroup report, June 2022, pages 6, 19.

- The economic lifetime of different components of the options will inevitably vary. In order to create an apples-to-apples comparison from a system life perspective, mid-life refurbishment or upgrades of equipment may be required as discussed below.

Recommendation #7: The alternatives must be clearly defined and demonstrated to be fully compliant with all the requirements and the implementation costs fully delineated.

c) *Economic lifetimes of compared solutions must be equivalent and reflect the requirements horizon*

Establishing the conditions for a fair comparison of the total costs of the alternative options is challenged by the inherent variability of their respective economic lives. Ensuring that all options are assessed against the same lifetime needs is important. However, wires solutions could have economic lifetimes of 60 years, while some components of DER solutions may only have a 20-year economic life. The BCA subgroup suggested that the lifetime used should reflect the longest expected service life among the alternatives, an approach consistent with transmission planning. [32] The IESO's non-wires alternative regional planning methodology includes future refurbishment or replacement investments for NWAs in order to deliver on the equivalent life of the wires solution.[33]

Recommendation #8: All options being compared by a BCA should capture the full costs and benefits over the same economic life.

d) *Fairly assessing costs to an LDC for Non-Utility-owned DERs requires additional examination*

FEIWG's mandate focused on non-LDC-owned DERs. The elements of the BCA framework described in this report are applicable to both LDC-owned and non-LDC-owned DERs. However, the assessment of non-LDC-owned DERs requires further examination to identify the costs of the DER options to the LDCs, including cost recovery from rate payers.

For the purpose of this discussion, the term DER Host refers to the 3rd-party DER owner/operator that is offering the DER as a service to the LDC. A distinguishing feature of non-utility owned DERs, is the DER Host's opportunity to accrue additional benefits that could be shared with the LDC to ultimately reduce the cost of the service. It is this circumstance that underpins why Host Impacts are identified as a consideration in the list of impacts identified by the BCA subgroup.

The direct cost impacts in a BCA for a non-utility-owned DER include:

- Direct equipment and connection Costs:
    - See Table 2
- Additional direct costs:
    - Transaction costs for both the LDC as well as the DER Host
    - ROI and fees for a DER Host
- Non-electricity system benefits
    - Internal to host (e.g. use of heat from a microturbine/CHP, benefit of backup, etc.)
    - Capital subsidies such as from the federal government (e.g. NRCan) for energy efficiency or other policy objectives

[32] FEIWG BCA subgroup report, June 2022, section 6.5 discusses the study period on page 31, exact method not resolved.
[33]IESO, Regional Planning NWA Assessment Methodology, Aug, 2022.

- Energy system benefits
  - DER Hosts may be able to seek revenues from several sources to offset their costs:
    - TOU driven demand side management benefits
    - Net Metering (NM) and ICI program benefits
    - Revenues from IESO Demand Response and other Grid/transmission services
  - Rate programs would apply generically to non-dispatchable assets. By making the assets dispatchable, it is conceivable that a storage DER, for example, could secure additional benefits for an LDC. For example, while an ICI program participant would shave system peaks, its dispatchability could help an LDC to avoid non-coincident peaks.

This list of impacts indicates that there are higher costs associated with non-utility owned DERs, which may be offset by multi-use benefits that accrue to the DER Host that may be unavailable to LDC-owned DER installations. More importantly, these additional benefits available to DER Hosts actually represent costs to rate payers and taxpayers. A fully scoped BCA should identify cost to the rate payer costs as system impacts and/or taxpayer impacts as appropriate.

Given the existent generous rate programs, there may be negligible incremental costs incurred in order for a non-utility owned DER to provide the services to an LDC. For an LDC to determine a fair recovery cost for rate payers, the analysis of the above noted benefits should be captured by the BCA with clear identification of the costs that rate payers and taxpayers would share. Including this analysis within the BCA would:

1) Help identify a "should cost" for LDC planning purposes
   - The "should cost" could inform an RFP and/or more effective LDC price negotiations.
2) Identify the system benefits achieved by the rate programs
3) Provide insights benefiting the BCAs for both existing and new DERs.

The BCA subgroup recommended that the BCA include raw cost assumptions for visibility.[34]

Existing DERs incented by the ICI program highlight the importance of these impacts. Many of these DER installations will have achieved their desired financial returns and delivered the intended system benefits. It is important to ensure that these benefits are validated and reflected in the planning assumptions and process and in the requirements underpinning the comparison of options. This helps avoid double counting. For ICI installations, payback is generally achieved in less than 5 years while assets have life expectancies of greater than 10 years. Class B rate payers already pay these costs as well as the ongoing premiums for the DERs participating in the ICI. For an existing DER, the only incremental cost would be for dispatch control, however the ongoing premiums paid by Class B rate payers may justify those additional costs being absorbed by the DER Host. It can be argued that the terms of the ICI program should be adjusted to require LDC dispatchability.

> **Recommendation #9**: The OEB should consider the potential for redefining the terms of existing government rate programs, i.e., the ICI to include LDC dispatchability, in order to reduce the costs to rate payers and taxpayers. This would be a useful adjunct to the joint IESO/OEB project to examine the alignment of incentives.[35]

[34] FEIWG BCS subgroup report, June 2022, section 6.8, page 31.
[35] IESO/OEB Joint Engagement Session Webinar, Nov 23, 2022.

4. Characteristics of Cost and Benefit Impacts Critical for Decision Making

This section identifies factors that could materially alter the outcomes of a BCA such as the fidelity of the electricity system modeling for both energy and capacity, including losses, environmental considerations and the nature of inputs required to address the societal factors of jobs, GDP and competitiveness the government is contemplating.[36]

The factors fall into five categories:

- Energy impact modeling considerations
- Capacity contribution modeling considerations
- Relevance of ancillary services
- Environmental factors
- Societal economic benefits

4.1 Modeling energy impacts

Robust modeling is required to quantify three aspects of energy impacts on the electricity system:

- Avoidable energy losses on the Dx and Tx systems;
- Operations impacts on energy from distributed generation resources; and,
- Energy losses incurred through the use of storage

Assessing these factors requires high fidelity modelling of the components of the total electricity system that are impacted by the solutions. These requirements and the reference case will characterize the incremental capacity and energy demand that must be satisfied by the solutions and their operational context.

a) Avoidable energy losses on the Dx and Tx systems

Energy losses in the Dx and Tx systems are a function of the load on those systems i.e., the load factor as a percentage of the grid's delivery capacity. When a wires solution upgrades the grid delivery capacity, losses are reduced 24x7, but as an exponential function of the real time load factor. Benefits are greater at higher loads.

When a DER is added that reduces load on the system, it will reduce the load factor for the periods when the DER is displacing load. In general, DERs will operate less than 100% of the time and for that reason, may have less opportunity to reduce load and create avoided line loss benefits. This anticipated operating DER duty cycle is a critical input and should be characterized for the analysis.

The reference case will define the existing infrastructure and its delivery capacity and these requirements will establish the new demand load conditions. If the same requirements are applied to both solutions, which they should be as described earlier, similar capacity contributions should have similar line loss benefits, except for any differences in the solution duty cycles. The comparative analysis requires that the anticipated line losses are forecast for each of the wires and

[36] Letter of Direction from the Minister of Energy to the OEB, October 21, 2022.

DER solutions when integrated with the existing infrastructure so that the relative outcomes can be captured within the BCA.

b) Energy impacts from operating distributed generation resources

A definition of the anticipated demand scenario sets the requirements to be met.

Wires solutions will typically assume that the generation will be provided by the bulk system. The BCA must capture the assumptions regarding whether that generation will be new build, or not, and the associated cost assumptions for those conditions.

The BCA should define and capture the costs of the DER solutions that include distributed generation. It is important to model the generation behaviors under all options as DER operating practices can differ from those of bulk system generation. For example, when a solar DG operates while gas-fired generation is on the margin, it will save generation from the gas asset. But if it operates when hydro or nuclear is on the margin (e.g. under conditions of surplus baseload), it provides no energy benefits but reduces the hourly price and increases the global adjustment.

c) Energy losses of Storage

Energy storage devices have a round trip efficiency loss e.g., lithium-ion batteries could incur 15% losses and compressed air storage about 35%. As a result, storage increases the energy required to meet the demand. There is a cost when gas-fired generation is on the margin and the batteries are being charged. Savings could be achieved during times of surplus baseload by avoiding wasting that surplus. However, it is worth noting that when the Pickering Nuclear Generating station retires by 2026, Ontario will no longer have any material surplus baseload.

The energy or load displacement benefits of discharging the battery are a function of its discharge cycle. If the battery is placed in service only to address the peak capacity needs, the energy benefits will be immaterial as peak conditions only exist for a few hours in the year. If it is operated more frequently, that would need to be characterized. As previously noted, the operating duty cycle also affects the line loss assessments. It is critical that these impacts are included in the BCA.

The above conditions surface two important analytical questions requiring answers:

- What are the energy profile impacts in terms of kWh and their timing?
- What are the price/economic impacts of these energy profiles?

Each question requires distinct analytical methods within a high-fidelity modelling of the electricity system, particularly when non-dispatchable and/or intermittent DG energy dynamics are present. A high-fidelity model requires a full 8760-hour model of demand and supply to determine the impacts for the LDC, bulk system assets, and on the hourly electricity price.

1) Energy profile modelling

The IESO recognizes the need for full 8760 modelling when conducting BCAs for the NWA assessments in regional planning.[37] The IESO has used this modelling primarily to identify peak capacity needs, however, the same fidelity is required to assess energy impacts in off peak times.

Analyses have shown that full system modelling identifies material implications on intermittent renewables and the use of storage when servicing demand fluctuations. High fidelity modeling shows that, in comparison to the typical average assumptions, 30% of the renewable energy could be unused, storage assets will at best realize only 50% capacity factors and there will be very little reduction in the need for bulk system peaking capacity.[38]

The high-fidelity modeling can identify the impacts on regulated versus unregulated bulk system generating assets and whether costs are saved or incurred by integrating DERs.

2) Forecast HOEP impacts

The hourly energy price is primarily a function of whether natural gas-fired generation is on the margin, the presence of constrained transmission zones and the capacity factor of the gas fleet at the time.

When gas-fired generation is on for most hours of the year, the difference between on peak and off-peak pricing is driven primarily by the capacity factor of the gas generators. It is important that the requirements being addressed are considered in the context of the resource adequacy of the electricity system. This information should be provided during regional planning as it will affect the modelling and the outcomes but can only be developed from a high-fidelity simulation of demand and supply. The BCA should include an IESO reference as to whether the DER generation has a small or large influence on price.

For example, the recent DER Potential Study assumed an unrealistic, highly constrained energy system with extreme estimated HOEP impacts.[39] The economic outputs from that analysis lack credibility and should not be used by decision makers.[40] Their assumption is not reasonable; in fact, the IESO changed its procurement targets prior to the DER Potential Study completion, but those changes were not reflected in the analysis.

Recommendation #10: BCAs should require the use of a full 8760 hourly modelling analysis to confirm energy impacts.

4.2 Assessing Capacity Contributions

As previously noted, determining the capacity contribution of an asset also requires detailed modelling like the IESO has applied to its NWA methodology. Two aspects of assessing the capacity contribution of DERs are not always considered:

- There is the average contribution that an asset may provide on a daily basis; and

[37] IESO, Regional Planning Update, NWA assessment methodology, August 2022.
[38] Strategic Policy Economics, DER in Ontario, 2018.
[39] Dunsky, DER Potential Study for the IESO, released October, 2022.
[40] PWU Submission to the IESO regarding the DER Potential Study, October, 2022.

- The contribution that must be assessed for reliability purposes with a focus on the Loss of Load Expectation (LOLE).

For example, the IESO has identified that solar may provide a peak contribution of 28%. In fact, the average output of solar at 5pm in the summer is indeed 28%, however by 9pm, which is still in the peak demand window, it is practically zero.

The LOLE calculation is a stochastic analysis that assesses the probabilities of resources being available at peak demand times. A stochastic assessment of LOLE's accounts for the risks associated with meeting the no more than 24 hours of loss of load requirement over 10 years. Full 8760-hour simulations of Ontario demand and solar output over three years show that the aggregated solar output at peak times from all the province's solar farms can indeed be zero. This means that regardless of what the assumed capacity contribution may be, the system analysis will require that the reserve capacity exists to ensure no LOLE event occurs.

This same analytical effort is required for any non-dispatchable asset with weather related variable output.

The DER Potential study conducted for the IESO assumed this 28% solar contribution to peak. Environment and Climate Change Canada (ECCC), on the other hand, indicated it may assume that solar provides no capacity value.[41] The detailed simulations of solar plus storage installations in Ontario shows that full gas backup equivalent to peak demand is required to ensure reliability.[42]

> **Recommendation #11**: BCAs should require the use of a full 8760 hourly modelling analysis to confirm capacity impacts.

4.3 System ancillary services additions/reductions

The IESO has stated on several occasions that there is minimal need for new ancillary services. The need for services and hence the economic benefits provided by a DER should be determined by the requirements the solution is intended to address. As ancillary services needs are primarily the domain of the IESO, these requirements should result from integrated regional resource plans (IRRPs).

When DER options increase the need for ancillary services, for example the intermittency of non-dispatchable renewable generation, these costs should be identified and attributed.

4.4 Environmental attributes

The Minister of Energy's letter of direction to the OEB emphasizes the importance of the environmental benefits of the transformation.[43] Including environmental attributes in a BCA should only occur when these attributes are "traceable" to official government policies or other related standards. These policies could stem from Federal, provincial, or municipal policies.

Federal Policy

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[41] ECCC Webinar on methodology for developing the Clean Electricity Regulation, Sept 2022.
[42] Strategic Policy Economics, DER in Ontario, 2018.
[43] Letter of Direction from the Minister of Energy to the OEB, October 21, 2022.

The IESO's current procurement approach does not include selection criteria for achieving emission reductions. However, the IESO does acknowledge that the Federal Clean Electricity Regulation (CER) could prevent the operation of gas-fired generation past 2035. The CER is an example of a regulation that may drive environmental attributes non-quantitatively and could simply rule out gas as the option or comparator in a BCA for new generation, or at least change the economics from shortening its useful economic life.

Provincial Policy

Ontario's approach to carbon pricing in the form of the Emissions Performance Standard (EPS) is an environmental attribute that is still subject to debate in Ontario. [44] The EPS assigns a negligible carbon price on Ontario's natural gas fired generation. It could be argued that new gas-fired generation will be less exposed to carbon pricing given the use of the best available technologies. Carbon pricing impacts should be addressed in the BCA as energy cost impacts since the carbon price will be reflected in the HOEP. Given this policy uncertainty, carbon pricing will continue to represent unresolved cost risks.

Municipal Policy

Many municipalities have passed resolutions banning new natural gas-fired generation within their jurisdictions. Distributed small-scale gas fired generation i.e., combined heat and power could be transparently assessed against the BCA requirements.

Recommendation #12: BCAs should address the impacts of environmental attributes that are traceable to policy requirements and/or transparent, data supported assumptions. Scenarios should be drafted for OEB consideration with any deviations from government policies being made clear to stakeholders and decision makers. The OEB should provide clear guidance pertaining to the treatment of any government environmental policies within a BCA with updates as policy evolves.

4.5 Societal considerations

The Minister's letter to the OEB noted the importance of including societal impacts in the interests of rate payers and to help secure the economic benefits from the transformation.[45] There are four societal considerations addressed in this section:

- Economic
- Energy security
- Industrial competitiveness
- Determining "who pays"

a) Economic

The primary measures of the economic impacts are GDP and jobs. The economic impact of DER and wires solutions stems primarily from the degree to which the products and services are sourced in

[44] Remarks by Minister Todd Smith at the 2022 Energy Roundtable, Nov 30, 2022.
[45] Letter of Direction from the Minister of Energy to the OEB, October 21, 2022.

Ontario, specifically, the domestic spend. The greater the portion of the cost spent in Ontario, the more direct jobs and GDP are created.

Incorporating GDP in a BCA involves several parameters:

- % of spend that is domestic to Ontario
  - Including the breakdown of labour vs materials for both capital and ongoing operations
- Relationship between the solution cost and total GDP that will be generated (e.g. inclusion of the indirect and induced factors)
- Jobs created for each option in terms per unit (e.g. $000) of spend
- Anticipated tax revenues (federal, provincial, municipal) arising from GDP growth

Recommendation #13: To simplify the individual BCA analysis, the OEB should develop guiding principles to define the GDP-related parameters for the different technologies deployed by DER or wires solutions. This guidance in place would facilitate the transparent calculation of GDP, jobs and tax revenues for comparison in a BCA.

b) Competitiveness of Ontario's businesses and industries

The cost of the options, the primary measure in a BCA, directly determines the competitiveness of the province's electricity rates, a driving consideration for businesses and industries and a critical comparator for helping to determine the lowest cost to rate payers.

Any resulting increase in GDP and government tax revenues could help support existing and new government policies that encourage industrial competitiveness e.g., the ICI. This consideration is explored further below in the discussion of "Who Pays?".

c) Energy Security

Energy security has become an important policy priority in the global energy sector, driven primarily by climate change and geopolitical tensions in places like the Ukraine. The Line 5 disruption and potential cessation of operations as raised by the Governor of Michigan is another example of how energy security could significantly threaten the established infrastructure. These in turn, impact both supply and price. The developments have impacted all energy sources. Prices for oil and natural gas have experienced significant volatility. Ontario's notable reliance on imported natural gas from the U.S has been subject to price increases set by the North American gas market. These also impact the price for electricity imports from Quebec. Pricing risks could be quantified for inclusion in the BCA net benefits outcomes.

As well, internationally based supply chains for solar panels, wind turbines, batteries and microchips have experienced significant disruptions. These risks are related to the domestic content that also drives GDP and could manifest as cost risks due to delays for construction projects or extended outages when waiting for parts.

Recommendation #14: The OEB should provide guidance on the general assumptions for energy security and how to weigh these factors when assessing DER and wires alternatives in the BCA.

d) "Who Pays?"

The BCA report considered the question of who pays in its discussion of distributional fairness to help establish cost recovery mechanisms for DER investments made by distributors. The following takes a closer look at the implications on rate payers and taxpayers of the BCA subgroup recommendation to include broader societal considerations are factored into the BCA.

The BCA subgroup identified that, in the context of the total system impacts, specific rate payer impacts did not affect the cost effectiveness of options. However, they do directly impact the distributional fairness of the cost recoveries being considered based on where the benefits accrue. Table 1 in Section 2.0 of this report identifies the impacts across the energy system that should be considered in a BCA and the instances where different oversight processes may apply. This perspective summarizes the jurisdictional mandates that underpin the BCA subgroup recommended actions for the OEB [where the OEB may or may not have a mandate to establish cost recovery] and raised the perspective that incorporating IESO-related impacts should be considered in their decision making.

This section raises some additional matters for consideration by the OEB: 1) Rate impacts on the different rate payer classes in each part of the electricity system; 2) impacts on local and provincial taxpayers; and, 3) Impacts of policy direction on rate program outcomes.

1. Rate payer Classes

   The rates associated with distribution and transmission systems are determined differently for each of the rate payer classes and is generally a function of their size and the peak demand placed on the system.

   However, the impacts of DERs can be distributed differently among rate payer classes depending on the methodology employed. To transparently disclose impacts, the BCA should identify the impacts as a whole to the distributor's customers and also for each of the rate classes within the distributor's rate base to the extent that they materially vary.

   This approach should also be equally applied to transmission and distribution rate payers but importantly also to Class A, Class B RPP, and Class B non-RPP energy rate payers. The impacts on energy rate payers are governed by OEB (e.g. RPP vs non RPP), IESO (global adjustment and HOEP) and government policies (e.g. ICI and NM programs).

   > **Recommendation #15:** BCAs should summarize the regulated or legislated premise for any variances that emerge between rate payers.

2. Impacts of DER on taxpayer owned crown corporations

   The energy impacts of DERs for existing capacity, capacity factors and operations of Ontario's electricity system have a direct impact on the financial performance of the owners. The price regulation of these facilities e.g., OPG's hydroelectric and nuclear assets, affect the financial returns to government and ultimately taxpayers. This kind of regulatory oversight also applies to publicly owned local distribution companies (LDCs) and, to a lesser extent to the province's largest transmitter, Hydro One, which has also issued shares to the public.

   For example, the installation of a non-dispatchable DER (e.g. NM) could result in a revenue loss for any OPG regulated hydro asset that is curtailed. This could negatively impact OPG's revenue streams to the government or the OEB could approve a variance allowing for the recovery of the costs via rate increases on rate payers in future years. This example highlights the importance the earlier recommendation regarding the important need for modeling the energy impacts.

3. Rate Program Design

Electricity rate program policies established by government are sourced in societal objectives. The ICI program was created to provide more competitive industrial rates for Ontario's manufacturers who compete with neighboring jurisdictions. Similarly, the Net Metering program is intended to support the adoption of BTM solar technologies and expand customer choice, despite the higher costs to the electricity system.

The ICI policy established that Class B rate payers would pay a proportionately greater share of the costs of the electricity system, similar to most other jurisdictions in North America. However, the ICI's unique design has surfaced several unintended consequences, including higher than expected cost shifting to Class B rate payers and more importantly, implications on both rate payer classes as a function of the global adjustment and the HOEP. As the HOEP increases, Class A customers will experience higher relative cost increases compared to Class B customers.

> **Recommendation #16:** The BCAs should address the impacts on energy costs pertaining to each rate class and transparently inform rate payers about these costs and their allocation among the classes.
>
> Fact-based BCAs can facilitate transparency and contribute to a ongoing knowledge base to help inform future rate designs.
>
> **Recommendation #17:** The OEB and government should extend the requirement for a BCA to the rate design and evaluation processes, including the impacts on rate classes.

5. Foundational Methods for Analysis

This section looks at the appropriate use of Net Present Value (NPV) financial analysis and the relevance of societal discount factors given that the OEB's primary objectives are to ensure the lowest cost to rate payers while meeting the requirements of the electricity system.

The BCA subgroup report indicated that the method for using NPV and the role of societal discount rates remained unresolved. The Minister's recent direction to the OEB emphasized the importance of making investment decisions in the interests of rate payers.[46] This is not the same as assessing financial returns on investments. This section explores how the financial assessment in a BCA can compare alternatives to best reflect the interests of rate payers.

NPV Financial Assessment Methodology Objectives

The NPV methodology is a measure used by investors to help assess the return on investment of various options available to them. A set of cash flow forecasts are developed by the investor and then a discount value is applied to reflect the desired return on investment. There are three challenges to the use of this financial investment model for assessing rate payer impacts:

1) Rate payers are not making the investments and hence the timing of the cash flows may not be aligned with rate payer expenditures;
2) Selecting a discount rate for a societal benefit may not reflect the cost objectives of either investors or rate payers; and,
3) Depending on the utility vs non-utility model, investors may be seeking different rates of return.

The PWU shared this observation with the IESO in its submission on their NWA methodology for regional bulk system investments.[47]

Rate Payer Interests

Rate payer interests are best served by the lowest cost solution that meets the needs of Ontario's electricity system. From a rate payer's perspective, this outcome is achieved at the least cost to the annual cash flows that are recovered via various charges on a consumer's bill. This means all of these impacts should be addressed by a BCA for the annual cash flow impact on ratepayers. This will require including the various rates of returns sought by investors being accounted for along with the appropriate principles that the OEB defines for setting rates.

Proposed Method

The most important processes for properly assessing the rate payer impacts of DER or wires alternatives, are those the OEB defines for rate setting and those for establishing the cost recovery of the global adjustment and HOEP. For example, with respect to third party, non-LDC-owned DER Host costs, the process needs to capture the impact of the annual cost of the services to the LDC.

This approach obviates the need to debate the virtues of societal discount rates. Future rate payer costs are just as important as today's. The ongoing cost of energy that they pay for is just as important to rate

[46] Letter of Direction from the Minister of Energy to the OEB, October 21, 2022.
[47] PWU submission to the IESO on its regional planning NWA assessment methodology, Sept, 2022.

payers as today's cost. Rate payers would expect their future cost in real terms to be the same or lower than today or at least be assured that the changes in rates have been responsibly minimized. Once the future cash flows have been identified for all assessed material impacts with consistent project life assumptions, identifying a simple metric to capture the net impact of the BCA could be done in several ways:

A. Simple summation

The net annualized cash flows of the impact to rate payers could be simply totaled.[48] Equivalently, an average could be used.

B. Use NPV with a Policy set rate of return

While rate payers consider their future energy bill as a relevant frame of reference, decision makers may have different views on priorities. NPV calculations, as a function of the discount rate, effectively devalue longer-term rate payer costs. The higher the assumed discount rate, the less material long-term costs to rate payers are considered to be. Clear and transparent policy direction would be required to establish an appropriate discount rate to be applied to reflect whatever policy priorities may be in play.

C. Weighted Average approach

A weighting methodology provides a transparent, balanced presentation of the relative importance of the longer-term rate impacts for decision making. Should decision makers wish to prioritize near term rate impacts, a higher weighting could be applied to near term rate payer cash flows in the averaging calculation mentioned above. For example, the rate payer impact for the expected standard 60-year BCA could divided into six 10-year periods with decreasing weightings. From a policy perspective, the justification of the weightings would not mask the result with a discussion of appropriate discount rates not germane to the rationale.

Net annualized cash flows for rate payers should be established first. In developing a policy for comparison, it should be considered that the above alternatives may not yield much variation. This is because the annualized cash flows provide a smoothing function via existing LDC/utility practices for OEB rate submissions.

Recommendation #18: The OEB direct that the outcomes of a BCA be presented in the form of the expected annualized cash flow impacts to rate payers, not investment and operations cash flows summarized by an NPV calculation.

[48] It is important that these cash flows are developed in real terms, or at a minimum reflect accepted inflation assumptions that could then be appropriately discounted.

6. Standardized Outputs for Confirming Option Selection

This section discusses a standardized format for a BCA to provide transparency regarding the impacts on rate payers and other stakeholders, to support assumption and outcome validation and to help inform decision making for option selection and cost recovery.

The sample output format at the end of this document outlines the informational elements that would support decision-makers, including electricity system asset managers, operators, rate payers and taxpayers.

This requires a transparent disclosure of the outcomes in a BCA for each impacted stakeholder and rate class to:

- Align with the jurisdictional responsibilities of the affected decision makers;
- Inform distributional fairness of costs and benefits to the different rate payer classes; and,
- Enable the OEB to arbitrate distributional fairness as per the BCA subgroup's recommendations.

Rate payer Impacts

Detailed cash flow projections are required for each impact element of the BCA as summarized in Table 3 to provide the transparency regarding any material rate impacts.

Recommendation #19: OEB should provide the template for reporting BCA outcomes.

Assumption Disclosure Supports Validation

As mentioned earlier, an important aspect of using the BCAs for decision making purposes is to allow impacted stakeholders to validate the assumptions used. The requires explicitly defining the assumptions for each impact, supporting facts and guidance e.g., by the OEB. Such a template would also benefit stakeholders in the preparation of BCAs and understanding of the outcomes.

Recommendation #20: The OEB should provide a template that summarizes the assumptions, traceability and guidance for summarizing the assumptions for a BCA. This should include the system requirements and modeling templates co-developed with the IESO.

Table 3 - Illustrative BCA Outcome Reporting Template

Impact Category	Rate Impact Area	Annual Cash flows by Year								Total Impact
		1	2	3	4	...	58	59	60	Sum
Distribution	3rd Party Contracted Services									
	Distributer Impacts to be recovered									
	Total distribution impacts									
	Small ratepayers									
	Large ratepayers									
Transmission	Total Transmitter impacts to be recovered									
	Small ratepayers									
	Large ratepayers									
Resources	Regulated Generation impacts									
	Unregulated generation impacts									
	Market price effects									
	Total Energy impact									
	Class A ratepayer impact									
	Class B RPP Ratepayer impact									
	Class B Non-RPP Ratepayer impact									
IESO	Total IESO Impacts (Bulk System operation & Ancillary services)									
Societal	Class A ratepayer impact									
	Class B RPP Ratepayer impact									
	Class B Non-RPP Ratepayer impact									
	Economc impacts									
	Subsidy Impacts									
	Taxpayer Impacts									