**EB-2024-1111**

Enbridge Gas

Compendium for Examination of Current Energy Group and Energy Futures Group re. Revenue Decoupling and Energy Transition Evidence

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## Revenue Decoupling

Enbridge Gas's Y factors should sufficiently integrate partial revenue decoupling mechanism(s) that materially and equitably address the throughput incentive in a manner that is supportive of continued electrification and the ongoing energy transition. A partial revenue decoupling mechanism should be designed to ensure that Enbridge Gas is indifferent to whether new customers are added to its system while still exposing the company to revenue variations attributable to weather risks.

The primary objective of revenue decoupling is to weaken the link between utility earnings and sales volume. Revenue decoupling is designed to enable greater energy efficiency improvements by reducing the "throughput incentive" – the inherent financial incentive that utilities have to sell more therms of gas.

Revenue decoupling is a tool that addresses the throughput incentive. When variable rates are used to recover costs that are fixed in the short term, the utility can increase its revenues by selling more energy without a corresponding increase in its costs. This creates a powerful incentive to grow sales and oppose measures that reduce energy usage. However, revising the rate structure to collect a greater share of revenues via fixed rates is not an appropriate solution. A high fixed charge approach to addressing the throughput incentive would undermine customers' incentive to conserve energy and impose greater costs on low-usage (and often low-income) customers.

Removing the throughput incentive means that customers do not overpay for the use of the utility's existing assets when usage increases and that the utility does not fail to recover its prudently incurred costs for those assets when usage decreases. It also eliminates the profit opportunity that increased energy sales represent and thus reduces the utility's financial incentive to oppose energy-efficiency or DSM measures.

Under traditional regulation, utilities can retain any additional revenue they receive when their sales exceed the forecast that was used to set their revenue requirement, creating a

[17] Ontario Energy Board. Enbridge Gas Application for 2024 Rate – Phase 1 Decision and Order. EB-2022-0200. P. 22-23.

clear incentive for a gas utility to oppose energy efficiency and DSM initiatives that would result in reduced sales. Under revenue decoupling, most, if not all, variations between a utility's expected revenue and actual revenue are "trued up" annually. If the utility sells less gas than expected, rates will increase the following year to make up for the shortfall, and vice versa if it sells more gas than expected.

**A Well-Designed Partial Revenue Decoupling Mechanism Should Leave the Utility Indifferent to Customer Additions or Reductions in the Near-Term**

As the OEB has previously concluded, the energy transition is expected to result in declining sales from small-volume customers. In such a regulatory environment, it is important that Enbridge Gas's incentive structure does not present it with a financial preference for increasing average customer use within the MRP period. In addition, Enbridge Gas should not be exposed to the risk of under-collecting allowed revenues related to its fixed costs if the number of connected customers were to decline over the relevant time period.

In the Phase 1 Decision and Order, the OEB directed Enbridge Gas to utilize a harmonized average use variance account that requires it to continue to assume weather forecast risk as a part of the ratemaking process.[18] This is akin to "revenue per customer" decoupling, whereby it is thought that customer count is somewhat more closely correlated with growth in non-production costs, stronger than either growth in system peak or growth in energy sales. The revenue-per-customer method may not be appropriate in an era of energy transition, where new customers may have significantly different usage patterns than existing customers – e.g., partial electrification or enhanced energy efficiency measures – or where existing customers may begin departing the system – e.g., full electrification – over the course of an MRP period. An average use variance account is inherently tied to customer counts and, therefore, may still expose Enbridge Gas to under-collection of allowed revenues attributable to its fixed costs should the number of customers decline over the variance account period.

Given the concern that the energy transition is expected to result in declining sales from small-volume customers, an average use variance, or revenue per customer decoupling mechanism, may not adequately address the utility's financial exposure to a decline in the number of customers. In lieu of an average use variance account, the OEB should consider an alternative approach – revenue per customer class. Like revenue per customer, revenue per customer class determines the appropriate revenue to be collected regardless of the

[18] Decision and Order, December 21, 2023, at 123.

level of demand from customers. Revenue per customer class, on the other hand, is indifferent to the number of customers on the system or to average customer use.

To address the OEB's expectation of declining sales from small-volume customers, the OEB should explore a harmonized revenue balancing account that allows for truing up collected revenues against allowed revenues in a manner that is not tied to customer counts or customer average use. Such a total sales-based approach to decoupling could be designed in a manner that does not true up any weather-related revenue variances, thereby continuing to ensure that Enbridge Gas bears weather-related risks.[19]

[19] It is important to note that a partial revenue mechanism that is not developed on a per-customer basis or tied to customer average use may decrease the utility's overall cost recovery risk. Accordingly, such a revenue decoupling design should be coupled with other alternative incentives to ensure that the structure remains balanced.

**M2.EGI-9**

**Reference:** Exhibit M2, pages 13 to 14

**Preamble:** CEG states: "Given the concern that the energy transition is expected to result in declining sales from small-volume customers, an average use variance, or revenue per customer decoupling mechanism, may not adequately address the utility's financial exposure to a decline in the number of customers. In lieu of an average use variance account, the OEB should consider an alternative approach – revenue per customer class. Like revenue per customer, revenue per customer class determines the appropriate revenue to be collected regardless of the level of demand from customers. Revenue per customer class, on the other hand, is indifferent to the number of customers on the system or to average customer use.

To address the OEB's expectation of declining sales from small-volume customers, the OEB should explore a harmonized revenue balancing account that allows for truing up collected revenues against allowed revenues in a manner that is not tied to customer counts or customer average use."

**Questions:**

(a) Please provide any references to gas utilities/jurisdictions that have revenue true-up mechanisms by revenue/rate class, including a link to the regulator's decision and key evidence.
(b) For any references provided, please indicate if the utility is a provider of both natural gas and electricity services.
(c) For any references provided, please also indicate whether the utility is subject to weather risk or not. If yes, does that mean a weather normalization adjustment is performed for each respective rate class before the true-up is calculated?
(d) For any references provided, please also indicate what type of rate setting mechanism is employed (i.e. cost of service, price cap, or another form of incentive regulation).
(e) Finally, if an incentive regulation rate setting mechanism is employed, please indicate if customer numbers and associated volumes are updated annually as part of the rate setting process.

**Responses:**

These questions are beyond the scope of evidence that CEG has been asked to prepare and far beyond what could be prepared within the proposed budget and time available for interrogatory responses.

However in response, the Hawaii Public Utilities Commission includes revenue decoupling to true up collective revenues to an annual revenue target in its establishment of a Performance-Based Regulation framework.[5]

[5] Hawaii Public Utilities Commission. Summary of Phase 2 Decision & Order Establishing a PBR Framework. December 23, 2020. Available at: https://puc.hawaii.gov/wp-content/uploads/2020/12/PBR-Phase-2-DO-5-Page-Summary.Final_.12-22-2020.pdf. p. 3.

**M2.EGI-10**

Reference: Exhibit M2, pages 13 to 14

Preamble: CEG states: "Given the concern that the energy transition is expected to result in declining sales from small-volume customers, an average use variance, or revenue per customer decoupling mechanism, may not adequately address the utility's financial exposure to a decline in the number of customers. In lieu of an average use variance account, the OEB should consider an alternative approach – revenue per customer class."

**Questions:**

(a) Please provide further details of how the revenue per customer class would work under Enbridge Gas's proposed/historical IRM frameworks.
(b) Please confirm why CEG is proposing a revenue decoupling mechanism as part of Phase 2 rather than in Phase 1 or Phase 3.
(c) Please confirm, if Enbridge Gas forecasts net customer growth over the IRM period the Company will lose revenue under CEG's revenue decoupling proposal in this scenario.
(d) Please confirm, if customers leave Enbridge Gas's system during the IRM period the average customer's bill will increase to make up for the shortfall in revenue (all else being equal).
(e) Please confirm the revenue decoupling proposal suggested by CEG is specific to in-franchise low-volume rate classes (residential, general service).

**Responses:**

(a) CEG directs Enbridge to Exhibit M2, pages 13 to 14. Further details of the revenue decoupling mechanism design and a more detailed accounting of its interface with Enbridge Gas's proposed/historical IRM frameworks are beyond the scope of evidence that CEG has been asked to prepare and beyond what could be prepared within the proposed budget and time available for interrogatory responses.
(b) CEG was engaged to provide its expert opinion and prepare evidence for Phase 2 of this proceeding. CEG views revenue decoupling mechanism design as core to its evaluation of incentive-based regulatory structures and their respective alignment with the public interest in the context of a dynamic energy transition. CEG would be open to providing further evidence during Phase 3 of this proceeding if asked to do so but finds the design of a decoupling mechanism relevant to Issue #2 of Phase 2 and thus worth introducing at this juncture.
(c) CEG cannot confirm with specificity whether or not Enbridge would "lose revenue" under CEG's revenue decoupling proposal if Enbridge Gas forecasts net customer growth over the IRM period. In general, CEG's proposed revenue decoupling design is intended to provide an annual true-up of actual revenues collected to match target revenues over that same period on a per-customer class basis. The net effect of such an approach would be to lower the overall risk of revenue under collection rather than increase it.

(d) CEG can confirm that, generally speaking, revenue decoupling mechanisms operate to "true-up" a utility's actual revenues when forecasted sales exceed actual sales. The true-up component of a revenue decoupling mechanism would operate to place a small upward adjustment on customers' bills to close that gap. In this sense, it would operate like the current per-customer variance account, which could also operate to increase a customer's bill under certain circumstances.

(e) CEG's revenue decoupling proposal does not specify whether it should be limited to in-franchise low-volume rate classes (residential, general service). There should not be structural limitations to applying the approach across all customer classes. That said, CEG would need to conduct further analysis to determine whether it may be appropriate to limit the decoupling mechanism design proposed to in-franchise low-volume rate classes.

**M2.EGI-11**

Reference: Exhibit M2, page 12

Preamble: CEG states: "However, revising the rate structure to collect a greater share of revenues via fixed rates is not an appropriate solution. A high fixed charge approach to addressing the throughput incentive would undermine customers' incentive to conserve energy and impose greater costs on low-usage (and often low-income) customers."

**Questions:**

(a) Please confirm if CEG considered direction and decisions from previous OEB consultations about rate design, incentive regulation plans, conservation programs or other items in developing its revenue decoupling proposal.
(b) If the answer to part a) is yes, please indicate the references to OEB work and explain what CEG considered and how this was taken into account in the CEG evidence.
(c) Please confirm how the OEB addressed the undermining of customers' incentive to conserve energy when fully fixed distribution charges were implemented for electricity residential customers.
(d) Please confirm if CEG considered how the Demand Side Management (DSM) Framework and the DSM Incentive Deferral Account incentivizes Enbridge Gas to promote energy conservation.

**Response:**

CEG is unable to answer these questions without a specific list of directions and decisions that the Company is asking about. CEG did review and consider the decision from the first phase of this proceeding.

**M2.EP-10**

**Reference:** Exhibit M2, page 12

**Preamble:** "The primary objective of revenue decoupling is to weaken the link between utility earnings and sales volume. Revenue decoupling is designed to enable greater energy efficiency improvements by reducing the "throughput incentive" – the inherent financial incentive that utilities have to sell more therms of gas."

**Questions:**

(a) Are the co-authors aware that Canada uses the Metric system, and that "therm" is not a Metric unit?
(b) When the co-authors refer to "revenue decoupling" are they referring to the separation of fixed and variable costs in rates charged to customers?
(c) Considering that Enbridge Gas has specific rates for applicable to each customer class, and that the recovery of fixed and volumetric costs is not the same for each rate, which rates do the co-authors believe should be decoupled?

**Responses:**

(a) Yes. Our understanding is that cubic metres is standard measurement unit in Canada. We also note that, at times, Enbridge Gas uses non-metric terms such as cubic feet[16] or MMBtu[17] on its websites and in its Gas Supply Plan. For reference, one therm equals 100 cubic feet or approximately 2.83 cubic metres.[18]
(b) No.
(c) CEG does not understand the question as posed. Revenue decoupling refers to various alternative regulatory mechanisms that address the throughput incentive, in which the link between a utility's unit sales of gas is loosened or "decoupled" from the utility's collection of target revenues.

[16] https://www.enbridge.com/about-us/gas-distribution-and-storage#:~:text=In%20September%202023%2C%20Enbridge%20Inc,Wyoming%2C%20Idaho%20and%20North%20Carolina.
[17] Enbridge Gas 2023 Annual Gas Supply Plan Update EB-2023-0072.
[18] Canada Energy Regulator, Energy Conversion Tables: https://apps.cer-rec.gc.ca/Conversion/conversion-tables.aspx?=undefined&wbdisable=true

**M2.EP-11**

**Reference:** Exhibit M2, page 11

**Preamble:** "Revenue decoupling is a tool that addresses the throughput incentive. When variable rates are used to recover costs that are fixed in the short term, the utility can increase its revenues by selling more energy without a corresponding increase in its costs. This creates a powerful incentive to grow sales and oppose measures that reduce energy usage. However, revising the rate structure to collect a greater share of revenues via fixed rates is not an appropriate solution.

A high fixed charge approach to addressing the throughput incentive would undermine customers' incentive to conserve energy and impose greater costs on low-usage (and often low- income) customers."

**Question:**

(a) It is not clear from the quoted paragraph what the co-authors are recommending. Are the co-authors recommending that less fixed costs should be recovered through the fixed monthly charge and more fixed cost should be recovered through the volumetric charge than is now the case? If the answer is yes, please explain why that is de-coupling. If the answer is no, please explain in detail what the co-authors are recommending.

**Response:**

No. Revenue decoupling can be achieved through a variety of regulatory mechanisms. CEG recommends that a mechanism be adopted to achieve revenue decoupling with respect to customer counts.

**M2.EP-12**

**Reference:** Exhibit M2, page 13

**Preamble:** "Under revenue decoupling, most, if not all, variations between a utility's expected revenue and actual revenue are "trued up" annually. If the utility sells less gas than expected, rates will increase the following year to make up for the shortfall, and vice versa if it sells more gas than expected.

A Well-Designed Partial Revenue Decoupling Mechanism Should Leave the Utility Indifferent to Customer Additions or Reductions in the Near-Term."

**Questions:**

(a) What is partial revenue decoupling and how is it different from revenue decoupling.
(b) Please describe in detail the mechanics of partial revenue decoupling.
(c) Are the co-authors recommending revenue decoupling or partial revenue decoupling?

**Responses:**

(a) Partial decoupling insulates only a portion of the utility's revenue collections from deviations of actual from expected sales.
(b) Under partial decoupling, any variation in sales would result in a partial true-up of utility revenues (e.g., 50%, or 90%, of the revenue shortfall is recovered).
(c) CEG is recommending partial revenue decoupling insofar as its recommendation would insulate only a portion of the utility's revenue collections from deviations of actual from expected sales. Consistent with past OEB guidance on the matter, CEG's proposed partial revenue decoupling mechanism would not insulate Enbridge from weather-related deviations of actual from expected sales.

**M2.EP-13**

**Reference:** Exhibit M2, pages 13 and 14

**Preamble:** "In lieu of an average use variance account, the OEB should consider an alternative approach – revenue per customer class. Like revenue per customer, revenue per customer class determines the appropriate revenue to be collected regardless of the level of demand from customers. Revenue per customer class, on the other hand, is indifferent to the number of customers on the system or to average customer use."

**Question:**

(a) Please explain in detail the mechanics of revenue per customer class and how it is different from the current cost allocation method used by Enbridge Gas.

**Response:**

Revenue per customer class, as referenced above, refers to a specific type of revenue decoupling mechanism design and not to a cost allocation method.

**M2.EP-14**

**Reference:** Exhibit M2, page 14

**Preamble:** "To address the OEB's expectation of declining sales from small-volume customers, the OEB should explore a harmonized revenue balancing account that allows for truing up collected revenues against allowed revenues in a manner that is not tied to customer counts or customer average use."

**Question:**

(a) Please explain in detail the mechanics of a harmonized revenue balancing account.

**Response:**

This question is overly burdensome and beyond the scope of CEG's evidence. The "harmonized revenue balancing account" refers to the Board's order for Enbridge Gas to establish a harmonized average use variance account in its Phase 1 Decision.[19]

[19] Ontario Energy Board. Enbridge Gas Application for 2024 Rate – Phase 1 Decision and Order. EB-2022-0200. P. 123.

**M2-SEC-4**

**Reference:** Exhibit M2, p.14

**Question:**

(a) Please explain what CEG means when it says "the OEB should explore a harmonized revenue balancing account that allows for truing up collected revenues against allowed revenues in a manner that is not tied to customer counts or customer average use." [emphasis added]. Is CEG recommending that the OEB undertake further study or consideration of such an approach, or implement it for Enbridge's 2025-2028 IRM term?

**Response:**

CEG recommends that modifications to the variance account also include more material changes to the variance account for application in Enbridge's 2025-2028 IRM term. CEG understands that changes to the prior variance account may be examined further in Phase 3 of this proceeding. CEG proposes that such an evaluation also consider more significant changes to the current variance account approach as reflected in CEG's Exhibit M2. To the extent that the OEB determines such changes are not warranted or desirable for Enbridge's 2025-2028 IRM term, CEG recommends, in the alternative, that the OEB undertake further investigation in advance of rebasing in 2029.

**M2-CCC-3**

Ref: Ex. M2/pp.12-14

**Questions:**

a) Please advise whether CEG's proposed "revenue per customer class" decoupling approach results in a true-up of revenues for both changes in average use per customer and customer count (but not weather). As part of the response, please explain how variances in demand/throughput relative to forecast caused by changes in weather relative to forecast is addressed in the proposed methodology.

b) Please provide a numerical example that highlights the operation of the revenue per customer class decoupling approach. As part of the response, please highlight how the utility retains weather risk.

c) Please advise whether the recommended comprehensive revenue decoupling approach (i.e., full true up of revenues related to both volumes per customer and customer count) has been implemented in any other jurisdictions. If so, please provide references to the relevant policy documents, decisions, etc.

**Response:**

a/b) CEG confirms that the "revenue per customer class" decoupling approach discussed in the evidence is intended to true up actual revenues for changes in sales volume per customer class (but not weather) and customer count per class. The variances in sales volume would be 'normalized' to account for weather changes to ensure the utility still holds weather-related risk. This approach to weather normalization could operate akin to the approach directed by the OEB in the average usage per customer variance account. The difference is that rather than applying weather risk and weather normalization to the average use per customer, the CEG proposed revenue decoupling approach would seek to true up actual revenues collected to authorized revenues due to changes to total sales volume per customer class, which would include sales declines due to customer departures – not just changes to average use per customer.

Note that there are other mechanisms that could be used to achieve the same goal of ensuing that the utility is made largely indifferent to customer additions or reductions, as discussed below.

A hypothetical example is provided below to help illustrate the operation of a revenue per customer class decoupling approach.

| Revenue Decoupling per Customer Class – Hypothetical Example | |
|---|---|
| Class | Residential |
| Allowed Revenues[5] | $2,000,000 |
| Collected Revenues[6] | $1,500,000 |
| Variance | $500,000 |
| Weather Normalization Adjustment | ($100,000) |
| Weather-Normalized Revenue Variance | $400,000 |

In the above hypothetical example, allowed revenues were $2,000,000 for the residential customer class. The utility under-collected revenues at a total of $1,500,000. Of the $500,000 variance, $100,000 of the loss in sales volume was attributable to weather. Accordingly, after a weather adjustment, the revenue variance to be trued up for the residential customer class is $400,000. This $400,000 would be collected via a minor increase in residential customer bills over a predetermined true-up period. This example would also work in the opposite direction to result in a negative variance if the collected revenues are higher than the allowed revenues. With a modest adjustment, the utility could be allowed to earn a percent of said revenue to account for incremental O&M costs of serving more customers.

The above hypothetical approach is comprehensive in its design, ensuring that the utility does not have an inherent structural preference for adding new customers over the plan period and would remain indifferent to customer departures as well. Moreover, the comprehensive per customer class revenue decoupling mechanism ensures that the utility is indifferent to reductions in customer usage. The Revenue Decoupling per Customer Class mechanism would be effectuated through a Revenue Balancing Account that would replace the existing Average Use per Customer Variance Account. Overall, it reflects a comprehensive approach to realigning structural financial incentives for the utility in an era of energy transition. In other words, the utility could not earn more revenue from increasing customer counts nor lose revenue from decreasing customer counts vis-à-vis the allowed revenues assumed in the test year.

[5] “Allowed Revenues” would be established during the test year on a per customer class basis. Allowed Revenues could be escalated year over year pursuant to the same I-X formula applied to the Price Cap mechanism.
[6] “Collected Revenues” would reflect actual revenues collected per customer class during the true-up interval, which could be monthly, quarterly, or annually.

In the alternative, should the OEB wish to preserve the existing Average Use per Customer Variance Account or prefer a different approach for other reasons, the core objectives of the Revenue Decoupling per Customer Class mechanism could be achieved through the creation of a Customer Count Variance Account. Under a Customer Count Variance Account approach, all or a portion of the revenue associated with net customer additions would be offset via the variance account. This customer count true up could be calculated against the customer counts for the test period. The variance account would record the revenue impact of the difference between the annual customer counts and those embedded in base rates for each of the general service rate classes.[7] The true-up likely should be offset by the incremental costs or savings from adding or subtracting customers of that class (i.e. the incremental O&M cost of serving an additional customer in the relevant rate class).[8] A hypothetical example is shown below.

| **Customer Count Variance Account – Hypothetical Example** | |
|---|---|
| Class | Residential |
| Net customer additions vs. test year[9] | 10,000 |
| Average revenue per customer[10] | $600 |
| Average incremental cost per customer[11] | $100 |
| Variance | -$5,000,000 |

This example would also work in the opposite direction to result in a positive variance if there are net customer losses. This example calculates the variance based on average revenue per customer. However, it may be possible for the utility to calculate the variance with more specificity using the actual billing data for customers that are connected to the system and those that exit the system. We do not know whether that is possible with the utility's information systems. Either option would be an improvement on the current approach.

[7] For example, a simplified calculation would be: [variance in customer counts] x [average revenue per customer], with the assumption that each customer connecting to the system or leaving the system does so halfway through the year.
[8] The calculation would be [variance in customer counts] x [average incremental costs per customer].
[9] This example assumes that 20,000 customers were connected throughout the current year, with each customer being connected to the system for an average of 50% of the year. In year 2, all of the customer additions from year 1 would be included plus 50% of the customer additions in year 2.
[10] This would be a weather-normalized figure to ensure that the utility maintains the weather-related risk. However, a non-weather-normalized figure could be used without negatively impacting the efficacy of this approach.
[11] The incremental cost per customer per rate class would be based on the test year and adjusted by I – X for each future year. Although this is likely the simplest and best approach, the incremental cost per customer could alternatively be held static for each of the future years or set each year based on actuals.

This variance account could be designed in a number of different ways and the design would depend on how much of the revenue from incremental customers it would be appropriate for utility to retain. The above example reflects a decision that the utility should be allowed to retain enough incremental revenue from incremental customers to cover incremental costs associated with those customers (and vice versa with respect to customer defections). But if the regulator felt it was appropriate for the utility to retain all of the revenue from incremental customers this could be achieved by recording and truing up the revenue impact of the difference between the annual customer counts and forecast customer counts. One ancillary benefit of establishing a customer count forecast is that it would illuminate the utility's assumptions and projections related to customer growth or defections.

As this discussion shows, there are a number of ways to make the utility indifferent to customer additions and customer defections. Our main point is that this is a very important step to take in light of the energy transition for the reasons outlined in our report. Any of the above options would be acceptable because they would give the utility the appropriate incentives. The Revenue Decoupling Per Customer Class option is the most comprehensive whereas the Customer Count Variance Account would be the simplest to add on to the existing framework.

c) The CEG recommended comprehensive revenue decoupling mechanism shares similarities with the Hawaiian Electric Companies' revenue decoupling mechanism.

**Reconciling Actual Revenue with Authorized Revenue**

Revenue Balancing Accounts (RBAs) record the monthly differences between target revenues and the adjusted recorded electric sales revenues. The RBA applies monthly interest, equal to the annual rate for short-term debt from the cost of capital in each HECO Company's last base rate case, to the simple average of the beginning and ending balances each month in the RBA. In effect, the RBA applies one-twelfth of the rate each month. Finally, the RBA provides for collection or return of the calendar year-end balances in the RBA over the subsequent year period. The target revenue is the most recent Authorized Base Revenue or the re-determined Authorized Base Revenue calculated.

The Company must file with the Commission a statement of the previous year-end balance in each RBA sub-account and the Authorized Base Revenue level for the current calendar year with supporting calculations. An amortization of the year-end balance in the RBA sub-accounts are recovered through the per-kWh RBA rate adjustments.[12]

[12] *See* Hawaiian Electric Company, Inc., Revenue Balancing Account ("RBA") Provision, Revised Sheet No. 92, Effective October 1, 2023, *available at* https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rates/heco_rates_rba.pdf.

ENBRIDGE GAS INC.

Answer to Environmental Defence Motion Question #2

Reference:

Exhibit M2, CEG Evidence, pp.12-14
Exhibit N.M2.CCC-3

Question:

Comment on the decoupling mechanisms described by the Current Energy Group's response to CCC interrogatory 3.

Response:

The evidence from Current Energy Group (CEG) states that a partial revenue decoupling mechanism should be designed to ensure that Enbridge Gas is indifferent to whether new customers are added to its system while still exposing the company to revenue variations attributable to weather risks.[1] The headline statement in the CEG evidence is that "A Well-Designed Partial Revenue Decoupling Mechanism Should Leave the Utility Indifferent to Customer Additions or Reductions in the Near-Term".[2]

Before commenting on the two specific decoupling proposals that CEG advances in its response to M2.CCC Interrogatory #3 (a question that CEG previously refused to answer when it was asked by Enbridge Gas[3]), the Company has several preliminary comments about Environmental Defence's (ED) general proposal to implement a decoupling mechanism that would make Enbridge Gas indifferent to adding new customers.

(a) Enbridge Gas is not indifferent to adding new customers. Enbridge Gas supports customer choice. New customers are asking the Company for connections. Enbridge Gas aims to add feasible customers and support economic growth in Ontario. Enbridge Gas has a statutory obligation to connect new customers. And when the Company adds new customers, the fair return standard dictates that it should earn a comparable return on the invested capital costs.

(b) It is not clear whether other parties in this proceeding are indifferent to adding new customers. More customers result in economies of scale, which puts downward pressure on rates for all. Adding customers is not in contradiction to

[1] Exhibit M2, CEG Evidence, p. 12.
[2] Exhibit M2, CEG Evidence, p. 13.
[3] Exhibit M2.EGI.9 and 10.

"to advance its performance-based approach to rate regulation".[5] That process is the better place to consider changes to the OEB's approach to IRM. It should also be noted that the proposal to implement revenue decoupling for at least the low-volume customer classes by using a variance account effectively creates a cap on the Company's revenues. That is not the OEB's policy under the RRF.

(g) Any mechanism that claims to make Enbridge Gas "indifferent" to adding new customers, by taking away the benefits that the Company would achieve from adding new customers (incremental revenues, for example), will lead Enbridge Gas to minimize the number of new customers that it adds (at least for most of the IRM term). The Company will not commit capital to such activities without the opportunity for future return.

(h) Ultimately, it is telling that CEG is not able to point to any equivalent mechanism in place in any other jurisdiction, aimed at reducing incentives to add customers in order to address stranded asset concerns. This belies the fact that there is likely no simple answer.

The Company will have more comments and responses as ED and CEG further define their proposal in the oral hearing and written submissions on this unsettled issue.

Turning to the two decoupling mechanisms described by CEG in response to M2.CCC Interrogatory #3, Enbridge Gas has the following comments. Please note that these are based on the Company's current understanding of the proposals, and on having had a limited amount of time to consider and respond to this request. Enbridge Gas may have further comments as the process continues.

[5] Advancing Performance-based Rate Regulation | Engage with Us (oeb.ca).

Proposal #1 - Revenue by Customer Class Decoupling Approach

CEG's evidence states:

> Given the concern that the energy transition is expected to result in declining sales from small-volume customers, an average use variance, or revenue per customer decoupling mechanism, may not adequately address the utility's financial exposure to a decline in the number of customers. To address the OEB's expectation of declining sales from small-volume customers, the OEB should explore a harmonized revenue balancing account that allows for truing up collected revenues against allowed revenues in a manner that is not tied to customer counts or customer average use.

In general, Enbridge Gas questions the premise of this proposed mechanism. This proposal seems to be based on an expectation of net general service customer declines, but Enbridge Gas is forecasting net general service customer increases over the coming IRM term.

In the response to M2.CCC Interrogatory #3, CEG provided an example of a revenue balancing account. The example notes that allowed revenues per customer class would be established during the test year (Enbridge Gas interprets this to mean that they would be based on its 2024 approved revenue requirement), and then escalated each year by the Price Cap IRM formula. In future years, Enbridge Gas would compare the revenues actually received to the expected revenues and refund or collect the difference, on a weather normalized basis.

A key problem with this mechanism is that it does not support Enbridge Gas recovering the increased costs that will be incurred from adding new customers. Under the Price Cap IRM, rates are not updated for an updated forecast of customers (or their associated costs). Therefore, if the base expectation of revenues is inflated only by the price cap, that will result in Enbridge Gas (all things being equal) refunding all incremental revenues associated with new customers and not recovering the incremental costs associated with those new customers. Said differently, Enbridge Gas would have new costs associated with the additional customers but its revenues would only recover the costs associated with the base level of customers (inflated per the Price Cap).

The costs associated with new customers are only part of the relevant consideration from the Company's perspective. Enbridge Gas not only looks to recover its costs but also has the opportunity to earn a margin from new customers. Any such margin would also be foregone under the CEG proposal. As seen in response to ED Question #3, the Company expects to have modest net revenues (margin) from customer additions in some rate classes over the coming IRM term. Additionally, the return on equity component of the Company's costs is considered to be "earnings" from the Company's perspective. The CEG proposal would see Enbridge Gas have to return these "earnings" to ratepayers.

In the response to M2.CCC Interrogatory #3, CEG notes "*With a modest adjustment, the utility could be allowed to earn a percent of said revenue to account for incremental O&M costs of serving more customers*."

Enbridge Gas acknowledges that this proposed "adjustment" could address the cost recovery concern above (assuming that all the incremental costs, such as O&M and capital, including carrying costs and taxes, are addressed), but it does not address the lost opportunity to generate margin. Where Enbridge Gas loses benefits from adding new customers, it is not "indifferent", and it is effectively punished for complying with the obligation to connect, and for facilitating customer choice and access to new housing. This harms Enbridge Gas's ability to operate in an environment similar to competitive, cost-minimizing, profit-maximizing companies, where growth decisions are encouraged in appropriate circumstances.

Importantly, the "adjustment" noted by CEG would not be "modest". The Company's near-term costs of serving a new customer are very close to the incremental revenues from the new customer. In response to ED Question #3, Enbridge Gas sets out preliminary estimated revenues and costs from adding new customers. As seen there, the O&M costs are only a small portion of the Company's costs to add a customer. The costs for depreciation, taxes and return on capital investment are much higher. It should be noted that the determination of what are the appropriate costs and revenues associated with customer additions is a complicated determination. Some of the questions that would likely arise are detailed below in the comments on the second CEG proposal.

Enbridge Gas notes that the proposed revenue by customer class reconciliation approach may lead to unintended consequences (from the perspective of the party advocating for this mechanism), whereby the Company, faced with customer growth, may seek to delay that growth to the end of its five-year term in order to add those investments to rate base as quicky as possible, minimizing its short-term foregone benefits and maximizing its long-term benefits of adding capital.

As a more technical point, the Company notes that if the revenue class true-up is net of incremental costs, the incremental costs incurred for additions will be different than the incremental costs saved for departures. For additions, incremental costs would include O&M and capital, while for departures only the incremental O&M would be avoided. The incremental O&M associated with departures may be different from additions.

Enbridge Gas notes that the customer signals/impacts may not be as CEG intends. For example in the event of customer declines (if that was to happen), if there is a true-up of revenue shortfalls then costs will go up for all remaining customers. Assuming that more affluent customers are more likely to be able to choose electrification options, this outcome would impose greater costs on low-usage and low-income customers. On the other hand, where customer additions continue to occur and the additional revenues are immediately credited to ratepayers, then this could have the impact of diminishing incentives for customers to moderate or reduce their consumption.

There are things that are not clear from the briefly described CEG proposal.

It is not clear if the proposal relates only to general service (small volume) customer classes. If so, this may create a symmetry concern. For example, where net increases in the number of general service customers are forecast over the IRM term, then Enbridge Gas would lose all upside benefits, while being left with potential downside risk of larger volume customer declines, all while continuing to bear the risk of weather variability.

It is also not clear how the proposal would work with the ICM mechanism. Questions arising include the following. How is capital of customer additions paid for, if there is an expectation that additional revenue is returned via the revenue per customer class true-up mechanism? Is growth in the ICM threshold formula zero? How does one determine what is incremental capital that isn't covered in base rates (i.e. even with zero growth, the ICM threshold could potentially still cover some growth capital spending).

<u>Proposal #2 – Customer Count Variance Account</u>

CEG's response to CCC Interrogatory #3 states:

> In the alternative, should the OEB wish to preserve the existing Average Use per Customer Variance Account or prefer a different approach for other reasons, the core objectives of the Revenue Decoupling per Customer Class mechanism could be achieved through the creation of a Customer Count Variance Account. Under a Customer Count Variance Account approach, all or a portion of the revenue associated with net customer additions would be offset via the variance account. This customer count true up could be calculated against the customer counts for the test period. The variance account would record the revenue impact of the difference between the annual customer counts and those embedded in base rates for each of the general service rate classes. The true-up likely should be offset by the incremental costs or savings from adding or subtracting customers of that class (i.e. the incremental O&M cost of serving an additional customer in the relevant rate class).

In the response to M2.CCC Interrogatory #3, CEG provided an example of a Customer Count Variance Account. The example shows that for each year Enbridge Gas would either recover or refund the incremental net revenue associated with the number of customer additions or departures. Effectively, Enbridge Gas would record the margin associated with the new (or departed customers) in the account.

Enbridge Gas has a number of concerns with this proposal, in addition to concerns already raised above.

First, and fundamentally, Enbridge Gas objects to the principle that benefits associated with customer additions must be credited back to ratepayers immediately. The reasons for this concern are addressed above. It is very clear from the example given by CEG that all margin associated with customer growth will be returned to ratepayers. In that scenario, Enbridge Gas is not indifferent to adding new customers. Instead, the utility is disincented to do so. There are more attractive ways to invest capital.

Second, it is not clear that the approach proposed by CEG will always make Enbridge Gas indifferent to adding customers. In the early years of the IRM term, the Company will not wish to add customers. But at the end of the term, there may be reason to do so, knowing that the new capital will soon be added to rate base.

Third, the Company notes that it will be a complicated process to determine the inputs into this Customer Count Variance Account. The determination of what is the appropriate level of revenue and cost to take into account will be contentious. Enbridge Gas has set out its preliminary views about the appropriate approach and inputs to consider in determining revenues and costs for customer additions in the response to ED Question #3. However, this matter is sure to generate further debate and would likely require detailed evidence, discovery and hearing process. This will likely make the account contentious. This is underlined by the fact that CEG assumes a margin of $500 per customer[6], and ED assumes a margin of $525 per customer[7], whereas the Enbridge Gas response to ED Question #3 shows that the margin per new customer is very small, and is negative in the early years for some residential rate classes.

Examples of questions that will arise include:

- Do incremental costs of customer additions include both O&M and capital costs?

- The incremental cost per customer is not linear. There will be stepped increases/decreases with the magnitude of customer increases or decreases (i.e. reinforcements required with a certain # of customers, or lower internal administration costs with a certain # of customer departures) that result from economies of scale over time. How will this be addressed?

- What should be included in the incremental capital cost to add customers. Is it an average cost?

- Is there an impact on calculation, treatment or application of contributions in aid of construction under this approach?

[6] See Exhibit M2-CCC.3, p. 9.
[7] See ED Motion, November 4, 2024, p. 2.

- Does the approach assume that all capital costs get included in rate base at the next rebasing? If there is some assumption of reduced inclusion (since the goal of ED's proposal is to reduce customer additions), then the associated lost earnings need to be taken into account in order to keep the utility "indifferent".

- The incremental capital cost associated with a customer addition changes each year (i.e. the annual revenue requirement of a customer addition varies due to tax implications and the declining carrying cost as the asset is depreciated). How is this taken into account?

- The incremental costs may differ depending on whether one is truing up additional customers versus customer losses. For customer additions, there is incremental capital and O&M, whereas for customer losses the capital has already been spent and there is only incremental/variable O&M savings. How is this taken into account?

- Incremental costs and revenues will vary by customer – it may be that customers leaving the system have higher or lower consumption than the average customer, for example, so that recovery of an average amount of consumption would understate or overstate lost revenues. Additionally, revenue per customer may also be different (as compared to the average) for new customers (or vary between customers). It is not clear how the mechanism deals with these items.

- Where average cost and revenue per customer are used for this mechanism, then it may be the case that the Company will be more inclined to add smaller low-cost customers and delay the addition of larger customers. It's not clear that's a desired outcome. Is this taken into account?

- Additionally, there will be questions around what is the proper base level of customers against which to calculate a variance. Is it the 2024 base year total customer forecast, or is it based on actuals? How are customer numbers determined for future years (is it an average number or a year-end number?)

Finally, Enbridge Gas notes that a customer count variance account would need to be utilized with the existing average use variance account. The average use variance account would capture average use variances, for recovery or refund, in relation to the base forecast numbers of customers, while the customer count variance account would capture impacts of customer numbers that differ from the base forecast.

ENBRIDGE GAS INC.

Answer to Environmental Defence Motion Question

Reference:

EB-2022-0200, Hearing Transcript, Volume Two, July 14, 2023, p. 22, ln. 14.

EB-2023-0201, Exhibit I.ED-23, Page 4, Table 2.

Question:

In relation to the Customer Count Variance Account described by the Current Energy Group, provide the average revenue per customer and the average incremental cost per customer for the general service customer classes, and if those figures differ significantly from $600 in average revenue and $74.89 in incremental costs for residential customers, to explain why.

Response[1]:

The $600 in average revenue is for all general service customers, not solely residential rate classes.

Enbridge Gas notes that the average distribution revenue, excluding DSM costs, for a residential customer is approximately $500. The incremental O&M for a Rate 1 customer based on the Phase 3 2024 Cost Allocation Study[2] and the O&M costs as approved in the Phase 1 Decision is $94.12. The incremental cost of $74.89 referenced in the question was the incremental O&M cost for a residential Rate 1 customer presented as part of the Eganville Leave to Construct Application[3]. The increase in cost is a result of the harmonized cost study and the length of time and change in costs since the last approved cost studies. Please see Table 1 for a summary of the average revenue and incremental O&M cost per customer by rate class for general service customers.

[1] Enbridge Gas wishes to indicate that this answer has been prepared as fully as possible in the time available. Enbridge Gas may have further information based on better understanding of the question being asked, and on having more time to consider and respond.
[2] This cost allocation study will be filed in Phase 3 and maintains current rate zones.
[3] EB-2023-0201, Exhibit I.ED-23, p. 4, Table 2. This cost was based on the 2018 cost study escalated by PCI annually.

Table 1
Average Revenue per Customer and Incremental O&M per Customer

| Line No. | | Number of Customers | Average Revenue/ Customer ($) | Incremental O&M per Customer ($) |
|---|---|---|---|---|
| | | (a) | (b) | (c) |
| 1 | Rate 1 | 2,163,088 | 485 | 94.12 |
| 2 | Rate 6 | 172,974 | 2,167 | 228.92 |
| 3 | Rate 01 | 369,871 | 616 | 118.80 |
| 4 | Rate 10 | 2,205 | 11,641 | 1,235.38 |
| 5 | Rate M1 | 1,205,199 | 493 | 95.36 |
| 6 | Rate M2 | 8,077 | 10,182 | 928.47 |
| 7 | Total General Service | 3,921,414 | 600 | |
| 8 | Total Residential | 3,738,158 | 500 | |

The incremental costs Enbridge Gas incurs for adding a customer includes the O&M cost as shown in the table above, as well as the capital cost. The average incremental cost of adding a residential customer, determined by the revenue requirement calculation that includes both the incremental O&M and capital cost is between $491 and $610 in Enbridge Gas's rate zones. Please see line number 16, column (e) in Tables 2 to 4 which show the average revenue requirement of attaching a feasible customer. Note, the costs underpinning Tables 2 to 4 are based on the best available information today, which is the Phase 3 2024 Cost Allocation Study for current rate zones.[4] The Phase 3 2024 Cost Allocation Study is used as it is the only cost study that has been updated for the revenue requirement approved in Phase 1. The assumptions Enbridge Gas made in order to develop the cost estimates include:

a) The distribution rates used in determining the customer addition capital expenditure are based on the Phase 3 2024 Cost Allocation Study (consistent with Table 1).

b) The capital expenditure per customer attachment is calculated to be equal to Enbridge Gas earning a PI of 1.0 over 40 years (line 1 of Tables 2 to 4). This is a notional number and does not consider the actual cost to add a specific customer

[4] The Phase 3 2024 Cost Allocation Study includes the revenue requirement approved as part of the Phase 1 Interim Decision and Rate Order (EB-2022-0200), but does not include costs from the Phase 2 Settlement Proposal.

which could be higher or lower. Enbridge Gas believes this approach of estimating the incremental capital cost of adding a customer is appropriate as Enbridge Gas's portfolio must be equal to or greater than a PI of 1.0.

c) The revenue assumptions exclude projects with a SES and TCS surcharge.

d) The O&M amounts included reflect average variable O&M costs of each rate class, and do not include fixed O&M costs which can increase or decrease in a stepped fashion with material changes in the number of customers served, or due to other drivers. Please see Table 1 for the incremental O&M per customer (also see line 3 of Tables 2 to 4).

Table 2
Estimate of Incremental Revenue Requirement of Attaching Feasible Rate 1 Customers

| Line No. | Particulars ($) | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| | Rate Base Investment | | | | | |
| 1 | Capital Expenditures | 4,548 | 4,548 | 4,548 | 4,548 | 4,548 |
| 2 | Average Investment | 4,304 | 8,667 | 12,899 | 17,001 | 20,972 |
| | Revenue Requirement Calculation: | | | | | |
| | Operating Expenses: | | | | | |
| 3 | Operating and Maintenance Expenses | 94 | 188 | 282 | 376 | 471 |
| 4 | Depreciation Expense | 120 | 250 | 381 | 511 | 642 |
| 5 | Property Taxes | 14 | 27 | 41 | 55 | 68 |
| 6 | Total Operating Expenses | 227 | 466 | 704 | 942 | 1,181 |
| | Required Return (1) | | | | | |
| 7 | Interest Expense | 132 | 265 | 395 | 521 | 642 |
| 8 | Return on Equity | 151 | 303 | 451 | 595 | 734 |
| 9 | Required Return | 282 | 569 | 847 | 1,116 | 1,376 |
| 10 | Total Operating Expense and Return | 510 | 1,034 | 1,550 | 2,058 | 2,557 |
| | Income Taxes | | | | | |
| 11 | Income Taxes - Equity Return (2) | 54 | 109 | 163 | 215 | 265 |
| 12 | Income Taxes - Utility Timing Differences(3) | (55) | (101) | (141) | (175) | (156) |
| 13 | Total Income Taxes | (1) | 9 | 22 | 39 | 109 |
| 14 | Total Revenue Requirement | 509 | 1,043 | 1,573 | 2,097 | 2,666 |
| 15 | Number of Customers | 1 | 2 | 3 | 4 | 5 |
| 16 | Average Revenue Requirement per Customer | 509 | 522 | 524 | 524 | 533 |

Notes:

(1) The required return assumes a capital structure of 62% debt at 4.94% and 38% common equity at the 2024 Board Formula return of 9.21%. The annual required return is as follows: Average Investment (row 2) * 62% * 4.94% plus Average Investment (row 2) * 38% * 9.21%

(2) Taxes related to the equity component of the return at a tax rate of 26.5%.

(3) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Table 3
Estimate of Incremental Revenue Requirement of Attaching Feasible Rate 01 Customers

| Line No. | Particulars ($) | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| | Rate Base Investment | | | | | |
| 1 | Capital Expenditures | 4,912 | 4,912 | 4,912 | 4,912 | 4,912 |
| 2 | Average Investment | 4,642 | 9,353 | 13,923 | 18,352 | 22,640 |
| | Revenue Requirement Calculation: | | | | | |
| | Operating Expenses: | | | | | |
| 3 | Operating and Maintenance Expenses | 119 | 238 | 356 | 475 | 594 |
| 4 | Depreciation Expense | 129 | 270 | 411 | 552 | 693 |
| 5 | Property Taxes | 32 | 64 | 96 | 128 | 160 |
| 6 | Total Operating Expenses | 280 | 572 | 863 | 1,155 | 1,447 |
| | Required Return (1) | | | | | |
| 7 | Interest Expense | 142 | 286 | 426 | 562 | 693 |
| 8 | Return on Equity | 162 | 327 | 487 | 642 | 792 |
| 9 | Required Return | 305 | 614 | 914 | 1,204 | 1,486 |
| 10 | Total Operating Expense and Return | 585 | 1,185 | 1,777 | 2,359 | 2,933 |
| | Income Taxes | | | | | |
| 11 | Income Taxes - Equity Return (2) | 59 | 118 | 176 | 232 | 286 |
| 12 | Income Taxes - Utility Timing Differences(3) | (60) | (109) | (152) | (189) | (168) |
| 13 | Total Income Taxes | (1) | 9 | 24 | 42 | 117 |
| 14 | Total Revenue Requirement | 584 | 1,195 | 1,801 | 2,402 | 3,050 |
| 15 | Number of Customers | 1 | 2 | 3 | 4 | 5 |
| 16 | Average Revenue Requirement per Customer | 584 | 597 | 600 | 600 | 610 |

Notes:

(1) The required return assumes a capital structure of 62% debt at 4.94% and 38% common equity at the 2024 Board Formula return of 9.21%. The annual required return is as follows:

Average Investment (row 2) * 62% * 4.94% plus Average Investment (row 2) * 38% * 9.21%

(2) Taxes related to the equity component of the return at a tax rate of 26.5%.

(3) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Table 4
Estimate of Incremental Revenue Requirement of Attaching Feasible Rate M1 Customers

| Line No. | Particulars ($) | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| | Rate Base Investment | | | | | |
| 1 | Capital Expenditures | 3,955 | 3,955 | 3,955 | 3,955 | 3,955 |
| 2 | Average Investment | 3,738 | 7,531 | 11,210 | 14,777 | 18,229 |
| | Revenue Requirement Calculation: | | | | | |
| | Operating Expenses: | | | | | |
| 3 | Operating and Maintenance Expenses | 95 | 191 | 286 | 381 | 477 |
| 4 | Depreciation Expense | 104 | 218 | 331 | 445 | 558 |
| 5 | Property Taxes | 26 | 51 | 77 | 103 | 129 |
| 6 | Total Operating Expenses | 225 | 460 | 694 | 929 | 1,163 |
| | Required Return (1) | | | | | |
| 7 | Interest Expense | 114 | 231 | 343 | 453 | 558 |
| 8 | Return on Equity | 131 | 264 | 392 | 517 | 638 |
| 9 | Required Return | 245 | 494 | 736 | 970 | 1,196 |
| 10 | Total Operating Expense and Return | 470 | 954 | 1,430 | 1,899 | 2,360 |
| | Income Taxes | | | | | |
| 11 | Income Taxes - Equity Return (2) | 47 | 95 | 141 | 186 | 230 |
| 12 | Income Taxes - Utility Timing Differences(3) | (48) | (88) | (122) | (152) | (135) |
| 13 | Total Income Taxes | (1) | 7 | 19 | 34 | 95 |
| 14 | Total Revenue Requirement | 470 | 961 | 1,449 | 1,933 | 2,454 |
| 15 | Number of Customers | 1 | 2 | 3 | 4 | 5 |
| 16 | Average Revenue Requirement per Customer | 470 | 481 | 483 | 483 | 491 |

Notes:

(1) The required return assumes a capital structure of 62% debt at 4.94% and 38% common equity at the 2024 Board Formula return of 9.21%. The annual required return is as follows:

Average Investment (row 2) * 62% * 4.94% plus Average Investment (row 2) * 38% * 9.21%

(2) Taxes related to the equity component of the return at a tax rate of 26.5%.

(3) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

# ENBRIDGE GAS INC.

Answer to Environmental Defence Motion Question

## Question(s):

Provide Enbridge's latest estimates of customer connections and exits by rate class over the rate term as well as the revenue it forecasts generating over that term from net customer additions by rate class.

## Response:

Table 1
Forecast Customer Additions

| Line No. | Particulars | 2025 | 2026 | 2027 | 2028 | Cumulative Revenue (1) ($ millions) |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| | EGD Rate Zone | | | | | |
| 1 | Residential | 24,511 | 23,653 | 22,550 | 21,471 | $ 108.4 |
| 2 | Non-Residential | 1,223 | 1,112 | 1,011 | 907 | $ 27.1 |
| | Union North | | | | | |
| 3 | Residential | 3,014 | 2,840 | 2,661 | 2,496 | $ 15.3 |
| 4 | Non-Residential | 181 | 162 | 140 | 120 | $ 17.1 |
| | Union South | | | | | |
| 5 | Residential | 10,912 | 10,477 | 10,069 | 9,704 | $ 46.2 |
| 6 | Non-Residential | 692 | 635 | 569 | 502 | $ 66.2 |
| 7 | Total | 40,533 | 38,879 | 37,000 | 35,200 | $ 280.2 |

Note:

(1) Cumulative revenue based on proposed 2025 Rates with high-level future year IRM adjustments for PCI and base rate adjustment for expensing capitalized indirect overhead. Residential additions are assumed to be Rate 1, Rate M1, or Rate 01 based on rate zone, and non-residential adds are assumed to be Rate 6, Rate M2, or Rate 10 based on rate zone. Billing units for customer additions based on rate class 2024 average use and assumed to be 50% effective in year of addition. Cumulative revenue calculation includes monthly customer charge, delivery commodity charge and Union South storage charge.

Table 2
Forecast Customer Exits

| Line No. | Particulars | 2025 | 2026 | 2027 | 2028 | Cumulative Revenue (1) ($ millions) |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| | EGD Rate Zone | | | | | |
| 1 | Rate 1 | 1,742 | 1,759 | 3,928 | 6,125 | $ (11.2) |
| 2 | Rate 6 | 133 | 133 | 309 | 483 | $ (4.6) |
| | Union North | | | | | |
| 3 | Rate 01 | 298 | 299 | 567 | 835 | $ (5.5) |
| 4 | Rate 10 | 2 | 2 | 3 | 5 | $ (0.7) |
| | Union South | | | | | |
| 5 | Rate M1 | 966 | 974 | 1,839 | 2,716 | $ (2.0) |
| 6 | Rate M2 | 5 | 5 | 10 | 15 | $ (0.2) |
| 7 | Total | 3,146 | 3,172 | 6,656 | 10,179 | $ (24.2) |

Note:
(1) Cumulative revenue based on proposed 2025 Rates with high-level future year IRM adjustments for PCI and base rate adjustment for expensing capitalized indirect overhead. Billing units for customers based on rate class 2024 average use and assumed to be 50% effective in year of exit. Cumulative revenue calculation includes monthly customer charge, delivery commodity charge and Union South storage charge.

# Motion for Full and Adequate Interrogatory Reponses

Enbridge Gas Rebasing Phase II – EB-2024-0111

Environmental Defence

November 18, 2024

Elson Advocacy

Elson Advocacy

# Overview

- Enbridge's IRM proposals heavily incentivize customer growth spending and opposition to beneficial electrification
- This is contrary to consumer interests
- Should "decouple" revenue from customer counts to reduce the incentive
- ED's evidence: supports the need for decoupling and outlines 2 implementation options
- Also seeking additional implementation options and analysis from EG
- Requested order:
  - Describe a number of options whereby it would be made indifferent to the number of customer connections and customer exits during the IRM term from a revenue perspective, and indicate which option it believes would be the most appropriate should the OEB decide to implement revenue decoupling with respect to customer counts.
- The rule 27 test: relevance and whether unreasonable efforts required

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# Context

- Enbridge incented to:
    - Connect as many buildings as possible
    - Dissuade existing customers from electriftying their homes
- Two source of incentives:
    - Return on growth capital (NOT addressed by decoupling proposal)
    - In-term incremental revenue from new customers (addressed by decoupling)
- In-term revenue incentive is major
    - Earn $600/yr from new customers
    - Lose $600/yr from electrifying customers
    - Worth $280 million in revenue over rate term from net new customers
- Windfall: $280 million is far more than the incremental costs

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# Contrary to customer interests

- Promotes financial risk-taking
  - >$1 billion in customer connections capital over rate term
  - Phase 1 Decision: Enbridge has not accounted appropriately for ET risks (p. 19-20)
  - Risks highest for new assets b/c of higher remaining asset life (CCI report, p. 45)
- Discourages beneficial electrification (e.g. heat pumps)
  - Customers can lower energy bills by switching from gas to all-electric heat pumps
  - Savings higher if compare cost of low-carbon gas to carbon-free electricity system
- Discourages cost-effective decarbonization pathway
  - EFG Evidence p. 11 & 49; Transcript Vol 6. p. 68, ln 25 to p. 69
  - Canadian Climate Institute decarbonization cost optimization study:
    - *"Electrifying almost all building heat is the most cost-effective path to net zero"* (p. 10)
    - *"Continued growth of the gas network is inconsistent with cost-effectively reaching net zero"* (p. 36)
- Windfall: far exceeds incremental costs not included in base rates

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# Avenues to grow customer counts

Incentive for Enbridge to push for:

- Developers to install gas,
- HVAC contractors to discourage fuel switching,
- Municipalities to ask for gas service,
- Customers to connect to gas (even with deceptive marketing),
- Customers to miss beneficial electrification opportunities, and
- Governments & OEB to implement pro-gas policies,

even where that is contrary to customer interests.

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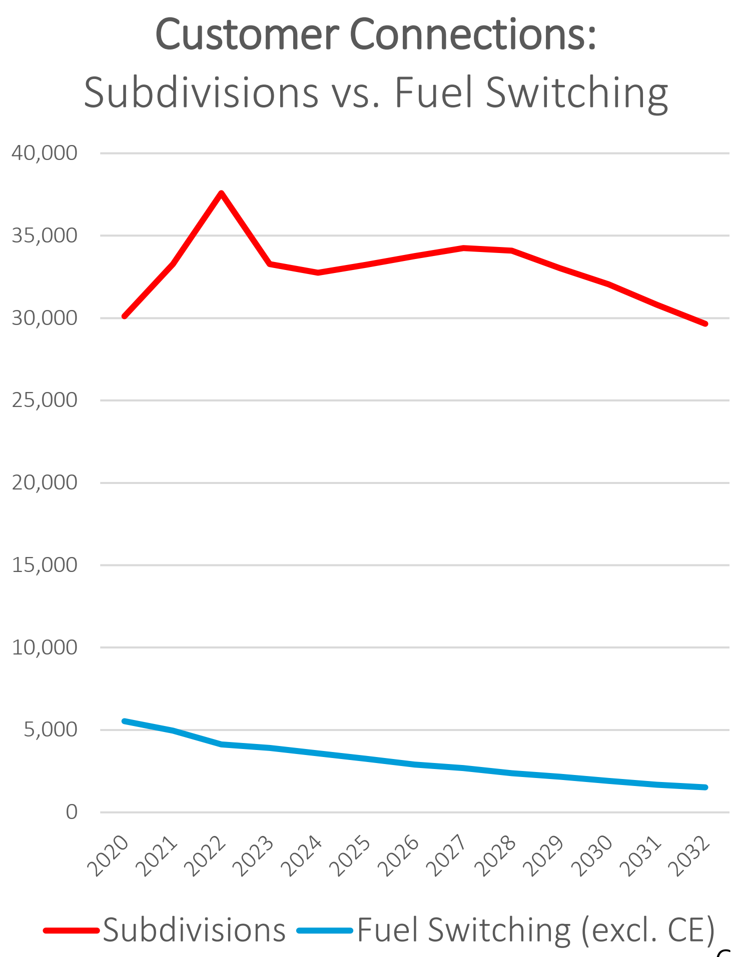
# Customer choice

- Decoupling achieves neutrality, NOT an end to connections or the obligation to serve
- More choice if Enbridge is neutral re connections/disconnections
  - Remove incentive to push for gas and discourage electrification
- More choice if risks/costs are reduced
  - Safeguards a viable gas system in the future
- Incenting EG to push developers to use gas does NOT promote customer choice
  - >90% of connections are by developers
  - Customer-driven connections are plummeting
  - (See right, Exhibit I.2.6-ED-94)



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# Provincial policy

- Affordability supports neutrality, not pro-gas incentive
- Ontario's Affordable Energy Future: The Pressing Case for More Power
  - Focus on electrification
  - "largest competitive energy procurement in the country's history"; "the largest battery storage procurement in Canada's history"; "largest expansion of nuclear energy on the continent"; "expanding our transmission network with new lines in all corners of the province"
- Viable gas network: Only possible if costs and risks are reduced
- New name: Ministry of Energy and Electrification
- The province plans to incentivize beneficial electrification, incl. fuel switching to heat pumps (See ERO Posting 019-9373)

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# Electrification and Energy Transition Panel

- Expert panel appointed by Ontario
- Highlighted risk of stranded gas assets & need for changes to regulatory mechanisms
  - "[E]merging evidence shows that it is unlikely the natural gas system can be fully decarbonized and continue to deliver cost-effective building heat."
  - "[T]here is a real risk of stranding assets in home heating and the gas distribution grid over the medium to long-term, with significant risk to customers, investors and public finances."
  - "[I]t is in the interest of the province, for the purpose of customer protection, to ensure that the regulatory mechanisms for the governance of the natural gas grid are aligned with a range of plausible outcomes, notably those that pose the greatest risks to customers."
  - See https://www.ontario.ca/document/ontarios-clean-energy-opportunity-report-electrification-and-energy-transition-panel-8#section-5

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# RRF & decarbonization

Enbridge says ED's proposal is at odds with the RRF & competitive markets

- RRF is meant to encourage efficiency and cost cutting, not incent behaviour that conflicts with customer interests
- Expansion incentive is inconsistent with a competitive market signals
  - *"In a less regulated sector, market signals would reduce the incentive that companies would have to pursue a strategy of continued network expansion in the face of potential demand declines. But gas utilities are partially insulated from these kinds of signals. They therefore have a strong incentive to advocate for pathways that require ongoing system maintenance or expansion…" CCI, p. 58*

Enbridge says adding customers "is not in contradiction to an affordable energy transition at least cost to ratepayers"

- Contrary to the evidence, e.g. EFG Evidence & CCI report:
  - *"Electrifying almost all building heat is the most cost-effective path to net zero" (p. 10)*
  - *"Continued growth of the gas network is inconsistent with cost-effectively reaching net zero" (p. 36)*
  - *""…low-carbon gases like hydrogen and biomethane will not serve as replacement fuels on a scale that can justify continued gas network expansion. Our modelling and numerous other studies find that these gases are either too scarce or too costly to heat more than a small fraction of Canada's buildings, and are instead taken up by other sectors such as heavy industry. Even under lower-cost assumptions for these fuels, electrification of building heat still dominates." (p. III)*

NEWS RELEASE

# Ontario Ready to Meet the Challenge of Soaring Energy Demand

Province prioritizing energy affordability for families and businesses as it plans for continued growth

**October 22, 2024**

Energy and Electrification

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**TORONTO –** Today, the Ontario government released *Ontario's Affordable Energy Future: The Pressing Case for More Power,* outlining the challenges facing the province as demand for energy continues to rapidly grow, as well as the province's path to managing this demand. The government also announced it would release the province's first-ever Integrated Energy Plan with a generational horizon out to 2050, which will ensure the entire energy sector is aligned behind the government's pro-growth agenda to reduce costs and province-wide emissions.

"Ontario's energy policy will literally determine the success of our province, today and for the next generation," said Stephen Lecce, Minister of Energy and Electrification. "Unlike previous governments that pursued siloed and short-term decision making that led to skyrocketing energy rates, our government will introduce the province's first integrated energy plan that will avoid the consequences of bad planning and ensure we have the affordable energy we need to power new homes, attract investment and create jobs."

According to Ontario's Independent Electricity System Operator, the province's demand for electricity is forecast to increase by 75 per cent by 2050, the equivalent of adding four and a half cities the size of Toronto to the grid. There is also continued demand for other fuels like gasoline and natural gas, that currently play a critical role in powering our vehicles, heating our homes and attracting new jobs in manufacturing, including the automotive industry and agriculture.

"Just like our great grandparents built the first hydroelectric dams at the turn of the century, our grandparents who launched the build out of our nuclear fleet in the 1960's, it will be our generation and our government that builds for our children and grandchildren," continued Minister Lecce. "Our competitive all-of-the-above approach will deliver more affordable power to our families – with non-emitting nuclear energy as our anchor – to keep costs and emissions down without a costly and unnecessary carbon tax."

*Ontario's Affordable Energy Future* outlines the challenges and priorities that must be addressed in the government's first-ever integrated energy plan to ensure the province continues to make new investments, including:

- **Integrated Planning for Growth**: Ontario's plan needs to coordinate all energy resources, including electricity, natural gas and other fuels, to ensure that the province's energy needs are anticipated and met in a coordinated and long-term manner, anchored by the largest expansion of non-emitting nuclear energy on the continent.
- **Affordability:** Ontario's plan needs to anchor energy affordability as a main driver in planning decisions by driving savings through competition, unlike previous governments that were driven by ideology.
- **Ontario's Alternative to a Carbon Tax:** Ontario's plan will never include a carbon tax. Instead, Ontario will meet its emission reduction targets with affordable and clean power that supports families and businesses to move away from higher emitting sources of energy.
- **Reducing Costs for Families Through Energy Efficiency:** Ontario's plan needs to provide ways to reduce energy consumption in addition to generating more power. The government will act on this priority ahead of an integrated energy plan by launching a significant expansion of energy efficiency programs on January 1, 2025.
- **Ontario as an Energy Superpower:** Ontario's plan needs to build on its competitive advantage and export clean energy and technology to the world, where it is in the best interests of Ontarians to drive revenue and jobs to our province.

This integrated plan will outline the total energy required by 2050, the financial investments to deliver on the need through the province's all-of-the-above approach to energy planning to reduce costs and province-wide emissions. The government intends to introduce legislation that would, if passed, support the implementation of this new energy plan and position the province to support electrification and energy affordability while competing for international investments which are looking for jurisdictions that provide access to clean, reliable electricity.

“Six years ago, the people of Ontario put their trust in us to end the previous government’s failed and ideologically driven energy experiments that burdened hardworking people and businesses with billions of dollars of bad deals,” said Sam Oosterhoff, Associate Minister of Energy Intensive Industries. “We got to work quickly on fixing the hydro mess. As a result, renewed access to clean and affordable energy has put Ontario back on the map for growing industries, but this is only driving demand for even more energy.”

To inform the province’s first integrated energy plan, the government has launched a consultation and engagement process with the public, Indigenous communities and other groups. These engagements will build on electricity generation and transmission announcements already announced as part of the province’s Powering Ontario’s Growth plan, including:

- **Ontario’s Largest Competitive Energy Procurement** – Advancing competitive procurement for new energy resources to Ontario’s growing energy needs.
- **Nuclear Energy** – Advancing reliable, affordable and clean nuclear power through pre-development work at Bruce Power, four small modular reactors at Darlington and supporting Ontario Power Generation’s plan for refurbishing the Pickering Nuclear Generation Station.
- **New Transmission Infrastructure** – Designating and prioritizing transmissions lines in Southwestern, Northeastern and Eastern Ontario that will power job creators including EV and EV battery manufacturing and clean steel production.
- **Additional Competitive Procurements** – A successful re-contracting of existing resources at about a 30 per cent discount and planning more competitive procurements for non-emitting electricity resources including wind, solar, hydroelectric, and bioenergy.

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**Quick Facts**

- Increasing electricity demand stems primarily from Ontario’s rapid increase in population, new manufacturing facilities, advanced technologies like artificial intelligence (AI) data centres, the electrification of industry, and the charging energy required for electric vehicles.
- The province will need nearly 2,200 MW of electricity for EV supply chain companies by 2050, the equivalent of 2.2 million homes.
- Industrial electricity demand is set to increase by 50 per cent in just the next five years.
- Ontario’s first Integrated Energy Resource Plan will be launched in 2025.

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# Ontario's Affordable Energy Future:

## The Pressing Case for More Power

OCTOBER 2024

MINISTRY OF ENERGY AND ELECTRIFICATION

Ontario

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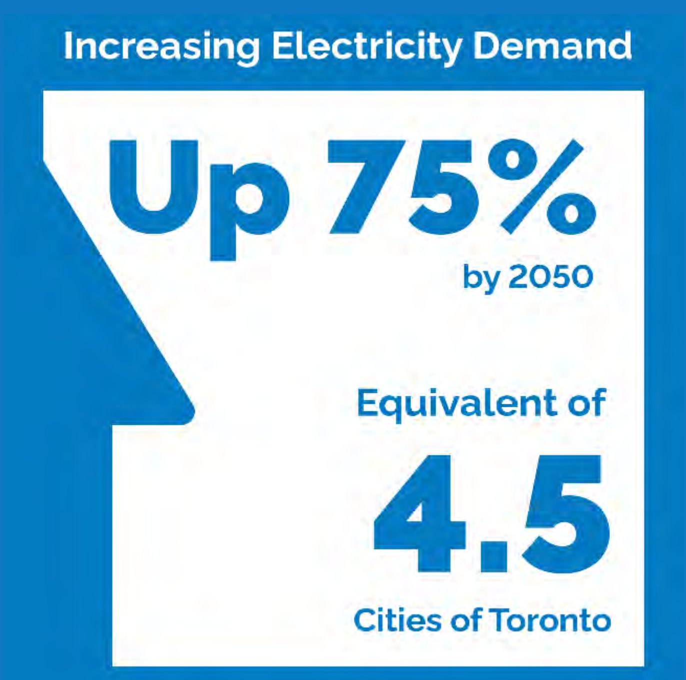
# Minister’s message

## Ontario’s energy policy will determine the success of our province, today and for the next generation.

Six years ago, the people of Ontario put their trust in us to end the previous government’s failed and ideologically driven energy experiments that burdened hardworking people and businesses with billions of dollars of bad deals that led to some of the highest increases in electricity costs on the continent. High energy costs that destroyed our manufacturing sector and eliminated more than 300,000 good paying jobs for people, and the families and communities that depended on them. They hired us to fix the hydro mess and bring back good jobs by restoring Ontario’s energy advantage.

We got to work.

Now, gone are the days of the previous government’s sweetheart deals that paid several times the going rate for power. Instead, we’re advancing a competitive all-of-the-above approach to meet growing energy demands while reducing emissions.




Gone are the days of families having to choose between putting food on the table or paying their energy bills. Instead, we’re keeping energy costs down for families and workers.

Gone are the days when skyrocketing energy prices drove businesses to leave Ontario. Instead, our government has lowered the cost of doing business in the province by $8 billion every year, including by lowering the cost of power.

As a result, we already have one of the cleanest grids in the world and renewed access to affordable and clean energy has put Ontario back on the map.

Companies and foreign investment are surging into our province, with $44 billion in new investment in electric vehicle and battery plants alone, with billions more in the province's growing tech and life sciences sectors. We're revolutionizing and connecting industries like world-leading electric-powered green steel production in Hamilton and Sault Ste. Marie and sustainably-sourced critical minerals from across Ontario's north to a growing manufacturing base.

These investments are creating better jobs with better paycheques in every region of Ontario. They're also putting new and unprecedented demand on the province's clean power grid.

Ontario's Independent Electricity System Operator (IESO) now forecasts that electricity demand alone is expected to increase by 75 per cent by 2050. That means Ontario needs 111 TWh more energy by 2050, the equivalent of four and a half cities of Toronto.

We need to take steps now to address this challenge. Failing to do so puts Ontario's economic growth at risk. We must do everything we can to protect jobs by strengthening our nuclear advantage which powers our status as the economic engine of Canada.

Planning for our future first requires that we understand the challenges ahead of us.

This document is the next step forward. It provides a full accounting of the challenges facing Ontario's energy system as we work with workers, regulators, sector stakeholders, builders, businesses, Indigenous communities and union partners to confront them. In doing so, this document also affirms our government's commitment to energy policies that keep energy rates down while supporting more jobs with bigger paycheques.

This is our choice. A pro-growth agenda that takes an all-of-the-above approach to energy planning, including nuclear, hydroelectricity, energy storage, natural gas, hydrogen and renewables, and other fuels, rather than ideological dogma that offers false choices and burdens hardworking people and businesses with a costly and unnecessary carbon tax.

Our government is choosing growth and affordability. Our vision is centered on the needs of families as we remain relentlessly focused on keeping costs down and growing Ontario's economy.

This is a vision rooted in ambitious work well underway. We've got shovels in the ground to prepare for the largest expansion of nuclear energy on the continent with the first small modular reactor in the G7 as we upgrade and refurbish existing reactors at Darlington, Pickering and Bruce Power to safely extend their lifespan, all on-time and on-budget. We are launching new energy efficiency programs, helping families reduce their energy use to save money. And we've launched the largest energy procurements of its kind in Canadian history to build the energy we need in the 2030s.

But there is so much more to do. We will not set Ontario up for failure because of a lack of ambition or desire to invest in our shared prosperity. We will do what previous generations have done for us: ensure that we put in place the building blocks for future success today. We will do this in partnership and consultation with Indigenous communities to ensure that everyone benefits from our energy investments and that we respect Aboriginal and treaty rights.

When we find that right balance, the opportunities for our prosperity extend beyond Ontario's borders. The truth is there is massive demand for clean energy around the world. Not only will we meet our own domestic demand, our government sees a chance to become an exporter of clean energy and clean tech to our neighbours and allies, which will lead to lower costs for our families and businesses, reduce emissions beyond our borders and promote North American energy security.

To get this right, however, we need to move away from the current siloed approach to energy planning that left previous governments playing catch-up. That's why I'm starting the work now to put forward a new, integrated approach that brings together every part of the energy sector to fuel our growing economy. Early next year, I intend to introduce the province's first ever integrated energy resource plan so that we can support economic growth for decades to come without ever burdening families with a costly carbon tax.

**Stephen Lecce**

Ontario's Minister of Energy and Electrification

# How We Got Here: Fixing the Hydro Mess

## Introduction

Prior to 2018, high energy costs were chasing jobs and investments out of the province. Between 2008 and 2016, the previous government signed more than 33,000 contracts that paid up to ten times the going rate for power, adding billions of dollars to energy bills for families and businesses. They also planned to shut down the Pickering Nuclear Generating Station rather than refurbishing it. They cancelled planning on critical infrastructure projects, including new nuclear at the Darlington site, leaving the province with limited options to power new homes and businesses.

As a result, demand for electricity flatlined as manufacturing jobs fled the province and businesses chose not to expand their footprint. Today, our government is reversing that trend. Over the past six years we've been focused on lowering costs for consumers while we build out new energy generation. That includes putting a plan in the window – *Powering Ontario's Growth* – to provide certainty for businesses and lay out the first steps of the province's plan to expand access to reliable, affordable and clean energy.

## Step One: Getting Electricity Bills Under Control

In 2018, electricity bills were out of control. Families were being forced to choose between heating and eating. Under the previous government's Fair Hydro Plans, electricity rates were expected to increase by about 5 per cent a year on average from 2025 to 2029 – representing a $28 dollar a month increase – which is unsustainable for families and businesses.

This was partially the result of 33,000 contracts signed by the previous government that paid up to ten times the going rate for power.

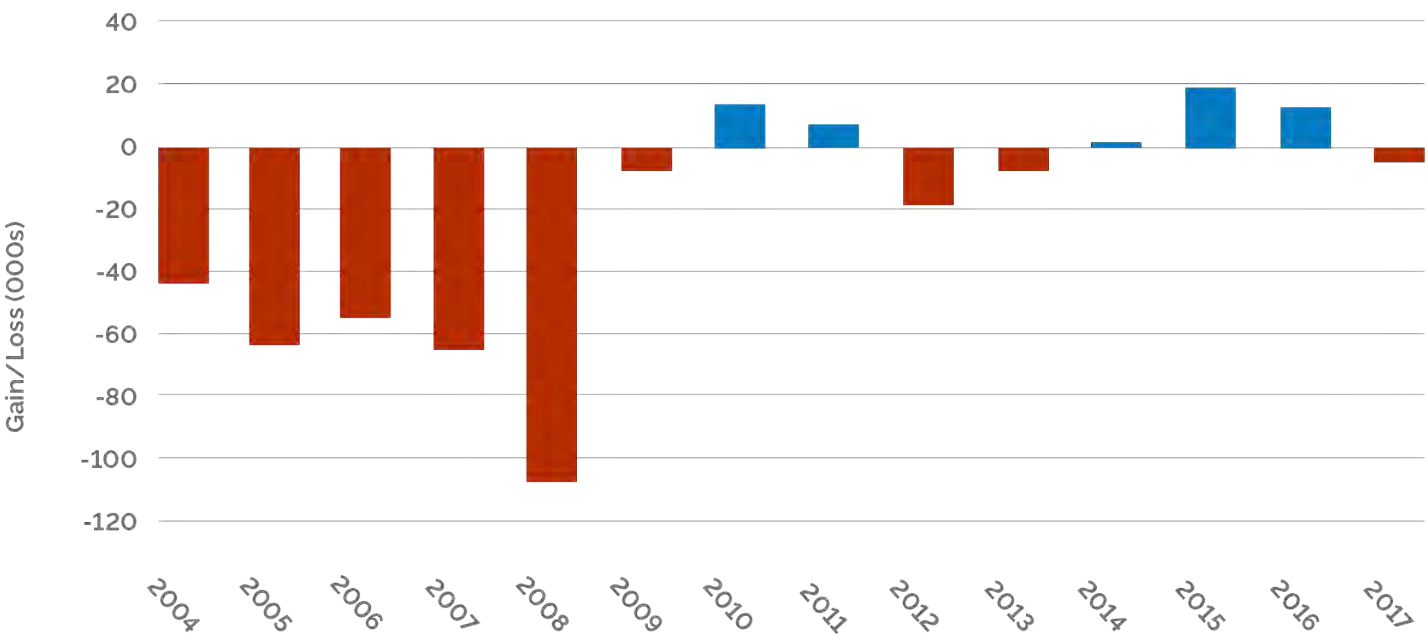
Rural and northern Ontarians were uniquely disadvantaged with fewer options to meet their energy needs.

Our government recognized it was not fair for ratepayers – whether they be businesses or families – to shoulder the burden of these overpriced and ideologically driven contracts. That's why the government moved forward with programs, including the Comprehensive Electricity Plan and the Ontario Electricity Rebate, to protect ratepayers and return stability to the province's electricity sector.

## Manufacturing Jobs Lost to High Electricity Prices

Ontario lost 300,000 manufacturing jobs between 2004 and 2018 as high electricity prices drove companies to other jurisdictions, including neighbouring US states. Each of those lost jobs represents lost income for families, making life more difficult in communities like Talbotville, Chatham and Leamington that saw manufacturing plants – like Ford Talbotville - close.

*Figure 1: Manufacturing Job Losses Per Year*




Source: Labour force characteristics by industry, annual (x 1,000)

## Comprehensive Electricity Plan (CEP)

Ontario's Comprehensive Electricity Plan (CEP) is lowering electricity costs for all consumers by funding the above-market costs of the approximately 33,000 existing renewable energy contracts, signed between 2004 and 2016. The need for this support will be reduced over time as 20-year contracts signed by the previous government come to an end.

### Ontario Electricity Rebate (OER)

Introduced in 2018, the Ontario Electricity Rebate (OER) provides electricity rate relief to eligible households, farms, long-term care homes and small businesses. The OER and CEP are automatically applied to consumers' bills.

*Figure 2: Sample Electricity Bills in 2023: With and Without CEP and OER*

**Sample Bill with OER and CEP**

Account Number: 000 000 000
November 2023

| | |
|---|---|
| Commodity | 96.21 |
| Commodity Adjustment due to CEP | -18.47 |
| Adjusted Commodity | 77.74 |
| Delivery | 49.32 |
| Losses | 3.80 |
| Regulatory | 4.07 |
| Subtotal | 134.92 |
| OER (-19%) | -26.04 |
| HST | 17.54 |
| **Total** | **126.42** |
| **Target Bill** | **126.44** |
| Base Delivery ($/700 kWh) | 49.32 |
| Base Commodity ($/700 kWh) | 96.21 |

**Sample Bill without OER and CEP**

Account Number: 000 000 000
November 2023

| | |
|---|---|
| Commodity | 96.21 |
| Adjusted Commodity | 96.21 |
| Delivery | 49.32 |
| Losses | 4.70 |
| Regulatory | 4.07 |
| Subtotal | 154.29 |
| HST | 20.06 |
| **Total** | **174.35** |
| Base Delivery ($/700 kWh) | 49.32 |
| Base Commodity ($/700 kWh) | 96.21 |

Source: Ontario Energy Board and IESO data; analysis by Ministry of Energy and Electrification

## Step Two: Powering Ontario's Growth

Our work to get electricity rates back under control has provided the certainty that businesses need to start investing, for the province to build new homes, and for consumers to electrify.

To provide businesses and builders with the certainty that power would be there when they needed it, we introduced *Powering Ontario's Growth* in June 2023. *Powering Ontario's Growth* laid out the first steps for new energy production including generational decisions, like starting pre-development work for a new nuclear station at Bruce, the first large scale nuclear build since 1993, and advancing four small modular reactors at Darlington, which will provide the dependable, zero-emissions electricity that businesses around the world are looking for.

### Nuclear

Nuclear power accounts for more than half of Ontario's electricity supply. It was critical in Ontario's efforts to phase out coal power generation and will be just as important as our economy electrifies and demand for energy grows. In addition to a proven safety record and ability to deliver a clean, reliable supply of the baseload electricity required by homes, business and industry, nuclear power has significant economic benefits.


## Nuclear Energy Creates Local Jobs

Ontario's three nuclear plants at Bruce, Darlington and Pickering directly employ close to 12,000 highly skilled workers, generate billions of dollars in economic activity and attract new jobs and investment to the province. Overall, Ontario's nuclear industry is one of the largest industrial employers in the province, supporting around 65,000 jobs. The nuclear industry in Canada also contributes around $17 billion per year to the national economy.

## Refurbishments

CANDU reactors require refurbishment after 30–40 years of operation. The Darlington Nuclear Generating Station and Bruce Nuclear Generating Station have now reached that point in their operating lives and refurbishments are underway. The Pickering Nuclear Generating Station will reach that stage in the coming years and the government has announced its support for refurbishing the station's four "B" units.

Altogether the refurbishments at Darlington, Bruce and Pickering would maintain more than 12,000 MW of existing generation capacity that will be necessary if our province is going to continue to grow.

## Nuclear: On-Time and On-Budget

In July 2023 Ontario Power Generation (OPG) achieved a major milestone by successfully connecting Darlington Nuclear Generating Station's Unit 3 back to Ontario's electricity grid after its three-year refurbishment, 169 days ahead of schedule. This world-class project performance demonstrates OPG and the nuclear sectors expertise and commitment to completing the station's four-unit refurbishment safely, with quality and on budget, by the end of 2026.

## New Build at Bruce Power

Ontario's Bruce Nuclear Generating Station (6,550 MW) is one of the largest operating nuclear generating stations in the world.

In 2023, the province launched pre-development work to site the first large-scale nuclear build in Ontario since 1993 at the existing Bruce nuclear site. In August 2024, Bruce Power submitted its Initial Project Description to the Impact Assessment Agency of Canada, officially kicking off the regulatory approvals process with the intent of locating up to 4,800 MW of new nuclear generation on the Bruce site, enough power for 4.8 million homes.

## Small Modular Reactor (SMR) Program

To meet growing demand, the province is also advancing four SMRs at the existing Darlington nuclear site which would provide a total of 1,200 MW of electricity generation, enough power for 1.2 million homes.

This "fleet approach" for SMRs in Ontario (i.e., building multiple units of the same technology) is providing significant benefits for the province's SMR program. For example, it reduces costs as common infrastructure such as the cooling water intake, transmission connection and control room that can be shared across four units instead of one. The modular nature of SMR manufacturing is also expected to reduce the cost of each additional unit.

Ontario's leadership in new nuclear technologies, particularly SMRs, is also raising the province's profile to an unprecedented level with other jurisdictions following Ontario's lead. In Canada, OPG is working with power companies in Alberta, Saskatchewan and New Brunswick as they work towards the development and deployment of SMRs in their jurisdictions leveraging Ontario's supply chains and expertise.

OPG and the province's world-leading nuclear sector are preparing to sell equipment to partner companies in the United States, Poland, Romania, the United Kingdom and other countries who are looking to deploy SMRs and watching Ontario's nuclear expansion closely, with more than $1 billion of export agreements already signed with Ontario-based nuclear supply chain companies that will see Ontario workers and companies be a workshop for the world – selling and exporting equipment we build right here in Ontario.

## Nuclear Energy Saves Lives: Medical Isotopes

This year more than 247,000 Canadians will be diagnosed with cancer, and two of every five Canadians will develop cancer during their lifetime. One of the most consequential tools doctors have available to diagnose and treat this disease will come from Ontario's nuclear generating stations: life-saving medical isotopes.

Ontario's nuclear fleet is at the forefront of innovation in the production of medical isotopes, in addition to generating reliable and emissions-free electricity. Ontario's nuclear power reactors currently supply about 50% of the world's Cobalt-60, a critical treatment for head, neck and cervical cancers, as well as for the sterilization of medical tools and supplies.

Ontario is also leading the world in the production of other isotopes in nuclear power reactors including Lutetium-177, used in targeted therapy for prostate cancer and neuroendocrine tumours and Molybdenum-99 which is used in diagnostic scans for bones, heart, lung, kidney as well as cancer detection.

## Hydroelectricity

Ontario built its electricity system on the power of water in the 1920s and today it continues to provide roughly a third of Ontario's total energy capacity and accounts for about 25 per cent of Ontario's electricity generation in 2022.

Some hydroelectric generating sites, like Niagara Falls' Sir Adam Beck facility, have served Ontario for more than a century and the province's commitment to the maintenance and upgrading of these facilities ensure that they will serve the province for the century ahead. In the past year the government has announced a total investment of over $1.6 billion to extend the life of these stations by an additional 30 years or more.

## Competitive Procurements

The government has adopted a competitive approach for procuring non-baseload electricity resources to drive costs down. Ontario has already conducted three competitive procurements to recontract existing resources and build new resources to meet growing demand.

Families and businesses are already seeing the benefits of this competitive approach. In the government's first procurement, the province successfully procured more than 700 megawatts of existing resources at a 30 per cent savings when compared to the previous government's contracts. This will result in lower electricity system costs and lower costs for ratepayers.


The government also concluded the largest battery storage procurement in Canada's history which secured nearly 3,000 MW of battery energy storage, as well as natural gas and clean on-farm biogas generation capacity, to support the province's growing population and economy through the end of the decade.

In August 2024, the government announced the next procurement, with targets that would make it the largest competitive energy procurement in the country's history. As part of that work the Minister directed the IESO to identify options to expand and accelerate this procurement to meet growing energy demands.

## Energy Efficiency

With demand increasing, the government has also expanded energy efficiency programs, an essential and cost-effective component of the province's plan. As Ontarians choose to electrify their homes and businesses there is an opportunity to install more efficient appliances and smarter controls to save money and energy while benefitting our energy system as a whole.

In September 2022, the provincial government increased funding for energy-efficiency programs by $342 million, bringing total funding to more than $1 billion over the current 2021–2024 framework. The government intends to build on this strong foundation and will unveil new energy efficiency programs aimed at helping families and businesses reduce their bills and save energy later this year.

## Energy Efficiency Programs Put Money in Families' Pockets

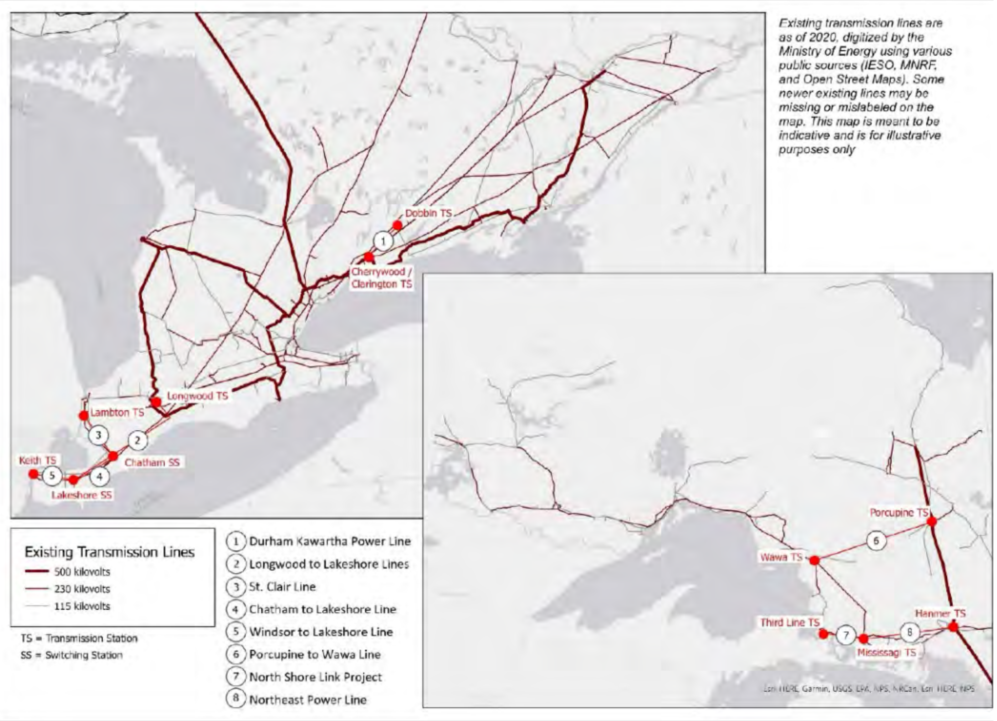
In June 2023 the government launched the new Peak Perks program to help families save money by reducing their electricity usage during peak periods. In just over a year, the program has already enrolled over 150,000 families and is providing them an upfront incentive of $75 and $20 for each additional year they stay enrolled in the program in exchange for reducing the use of their air conditioning system at peak times when the electricity system is strained. This makes it the fastest growing virtual power plant (VPP) in North America, which can reduce peak demand by up to 150 MW, the equivalent of taking the City of Barrie off grid at summer peak.

## Transmission Expansion

High voltage transmission lines act as a highway that carries electricity from where it is produced to directly connected large customers and local utilities. As the province builds out new generation, we're also expanding our transmission network with new lines in all corners of the province to get that energy where it needs to go.

Over the past six years, the government has accelerated development for five new lines in southwestern Ontario to meet growing demand from auto manufacturing and agriculture, two new lines in northeastern Ontario to support Algoma steel's planned conversion to electric steelmaking as well as mining opportunities, and one new line in eastern Ontario to support demands in the Peterborough and Ottawa regions.

*Figure 3: Transmission Expansion Map*

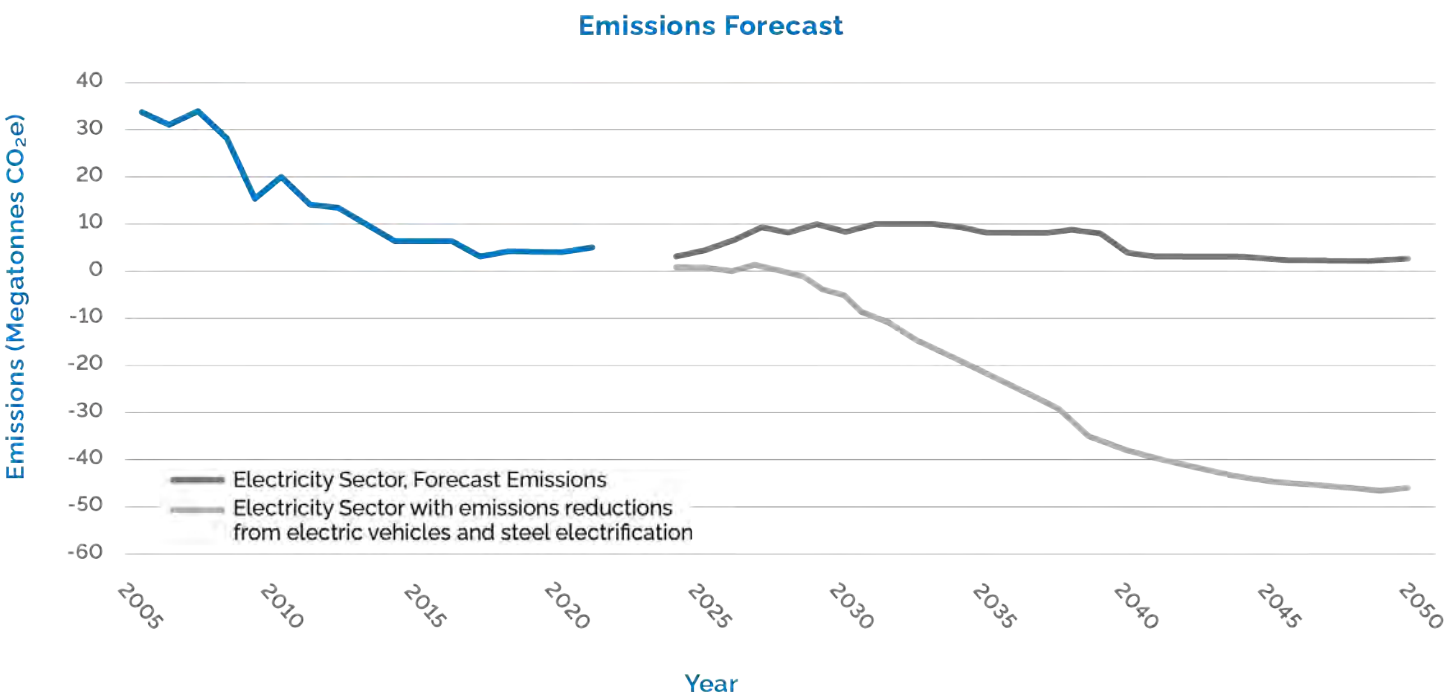


# Step Three: Ontario's Clean Grid Reduces Provincewide Emissions

Ontario's expansion of clean energy generation has already put the province on the path to reduce province-wide emissions through the electrification of the economy, even with a small increase in emissions produced by using natural gas for electricity. It has also supported the province being on track to meet its 2030 emissions targets, unlike the federal government and other provinces.

According to a 2024 estimate by the IESO, by 2035, through electric vehicle adoption and electrification of steel production, province-wide emissions may reduce by a magnitude of about three times that of the electricity sector. Overall, this amount could represent the equivalent emissions reduction of taking over three million gas-powered cars off the road.

*Figure 4: Province-wide Emissions Forecast*



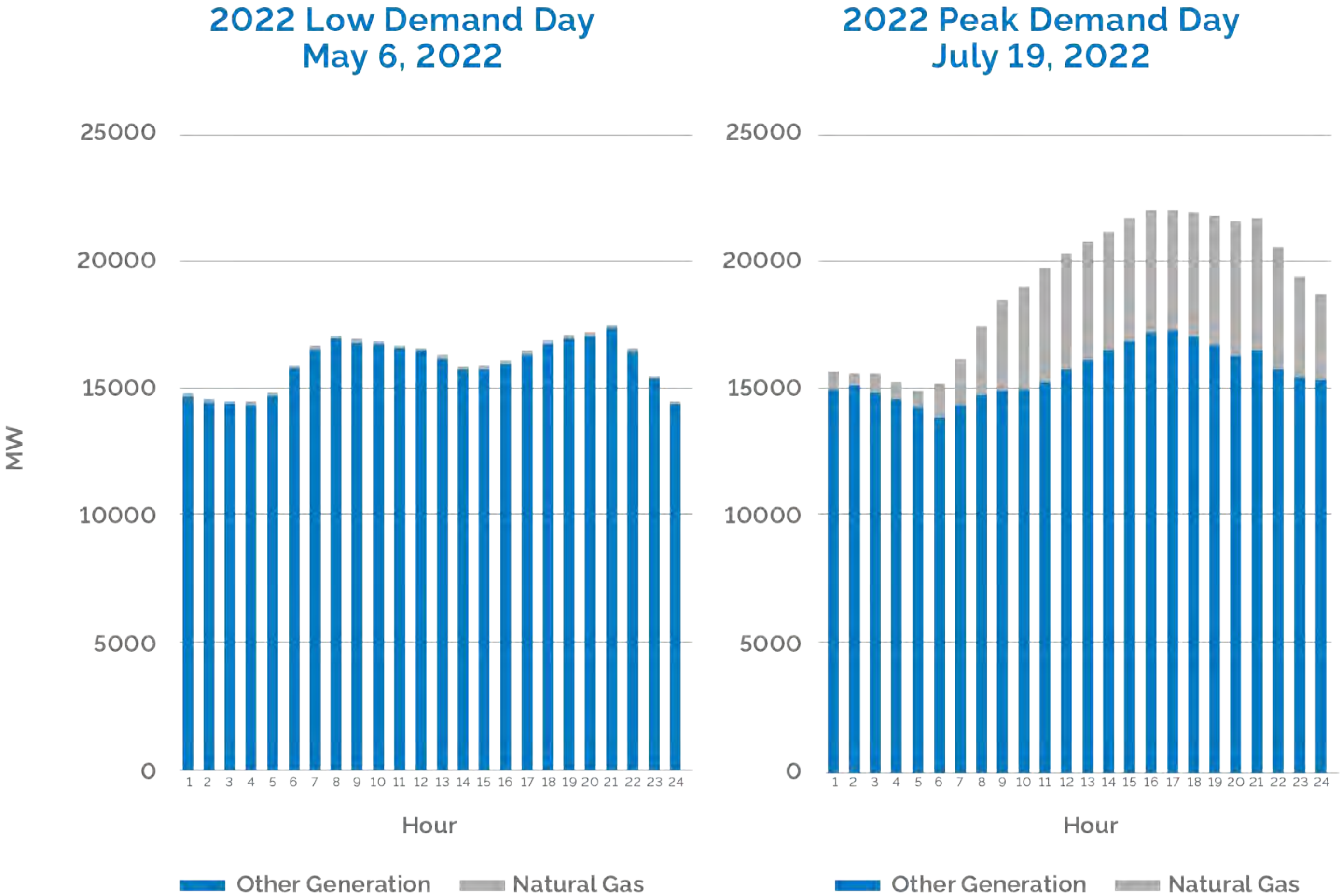

Source: Historical data sourced from Environment and Climate Change Canada's 2024 Greenhouse Gas National Inventory Report

The IESO's analysis also confirms that by 2040 electricity sector emissions will be lower than 2016 levels, once nuclear refurbishments are complete and new non-emitting sources of power like those the government is procuring and building today come online.

This emissions reduction opportunity is also built on consumers choosing clean electricity and switching away from fuels that have higher emissions.  Whether it is a family deciding to install an electric heat pump in the home or a mining operation considering an all-electric mine, these choices require consumer confidence that our clean electricity system will remain reliable and affordable over the long term.

## Why Ontario Needs Natural Gas in the Short-Term

*Figure 5: Energy Supply Mix May 6, 2022 (16˚C max) and July 19, 2022 (34˚C max)*




**May 6 2022**
Chart showing electricity generation on May 6, 2022 including natural gas generation compared to other generation sources. It was a mild day that required a minimal amount of natural gas generation.

**July 19 2022**
Chart showing electricity generation on July 19, 2022, including natural gas generation compared to other generation sources. It was a hot summer day when a higher amount of natural gas generation was required due to increased demand from air conditioning.

Source: IESO

In Ontario, nuclear power and hydro generally provide the continuous zero-emissions baseload power needed to ensure system reliability and meet minimum daily demand. Additional power is required to meet peak electricity demand, such as when the weather is hot and air conditioners across the province are turned on. Natural gas is the province's insurance policy, providing this reliability on the hottest and coldest days of the year when other resources like wind and solar are not available.

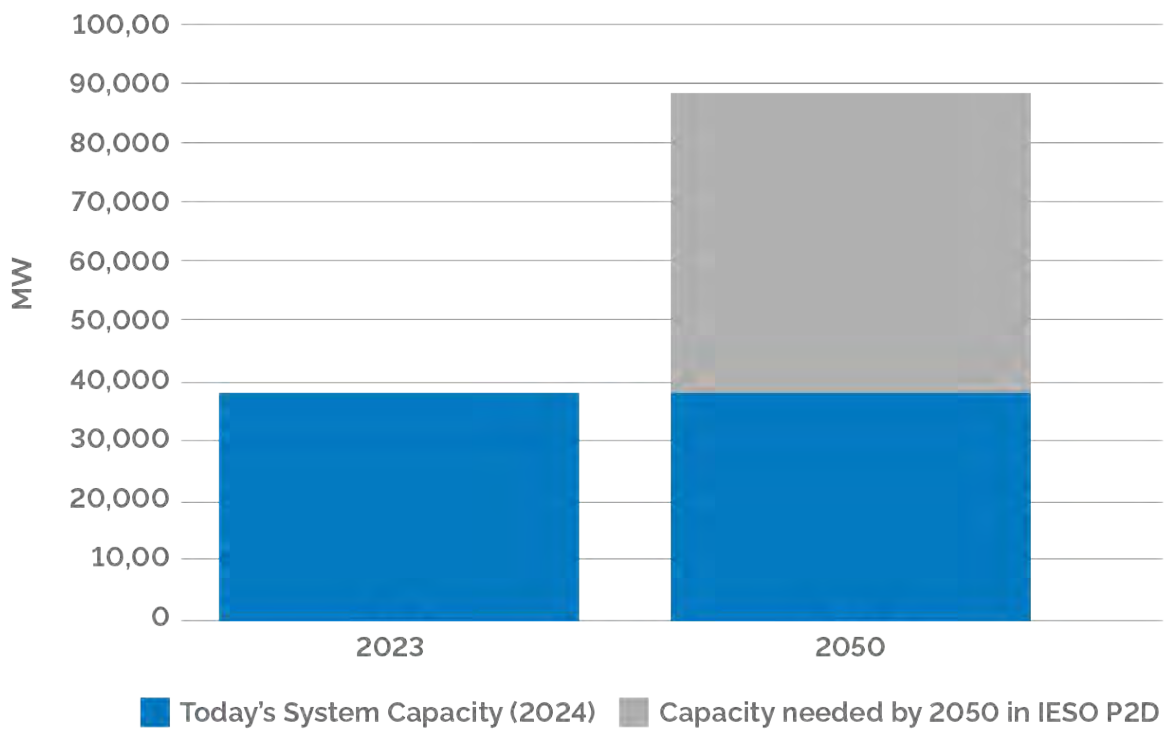
This is consistent with the expert advice of the system planners at the IESO whose Resource Eligibility Interim Report says: "Without a limited amount of new natural gas in the near term the IESO would be reliant on emergency actions such as conservation appeals and rotating blackouts to stabilize the grid."

# Going Forward: Economic Growth and Electrification Driving Energy Demand

Ontario's economy and the day-to-day lives of its 15 million residents depend on a reliable electricity system that delivers power on demand. As a result of a historic run of investments and unprecedented economic growth, demand on that system is growing quickly.

According to the IESO's latest forecast, demand for clean, reliable and affordable power is expected to increase by 75 per cent by 2050, an increase of 15 percent over the previous year's forecast. A 75 per cent increase in demand would require 111 TWh of new energy – the equivalent of four and a half cities of Toronto.

*Figure 6: Ontario Electricity System Capacity 2024 vs. 2050*




Sources: IESO website. 2023 Year In Review. IESO. Pathways to Decarbonization report.

This growth will be driven primarily by economic growth, continued increases in Ontario's population, mining and steel industry electrification and through Ontario's success in attracting unprecedented investment in Ontario's industrial base, including the electric vehicle supply chain. In fact, five major investments alone are expected to increase industrial demand in the province by the equivalent of 36 per cent of today's industrial load, almost the entire demand of the City of Ottawa (figure 7). In Windsor, NextStar Energy, a joint venture between LG Energy Solution, Ltd (LGES) and Stellantis N.V., is investing more than $5 billion to manufacture batteries for EVs, which at the time in 2022 represented the largest automotive manufacturing investment in the province's history.

Since then, Volkswagen Group announced a $7 billion investment to build an EV battery manufacturing facility in St. Thomas. The plant, Volkswagen's largest to date, will create up to 3,000 direct and 30,000 indirect jobs. Once complete in 2027, the plant will produce batteries for as many as one million EVs a year, bolstering Canada's domestic battery manufacturing capacity to meet demand now and into the future.

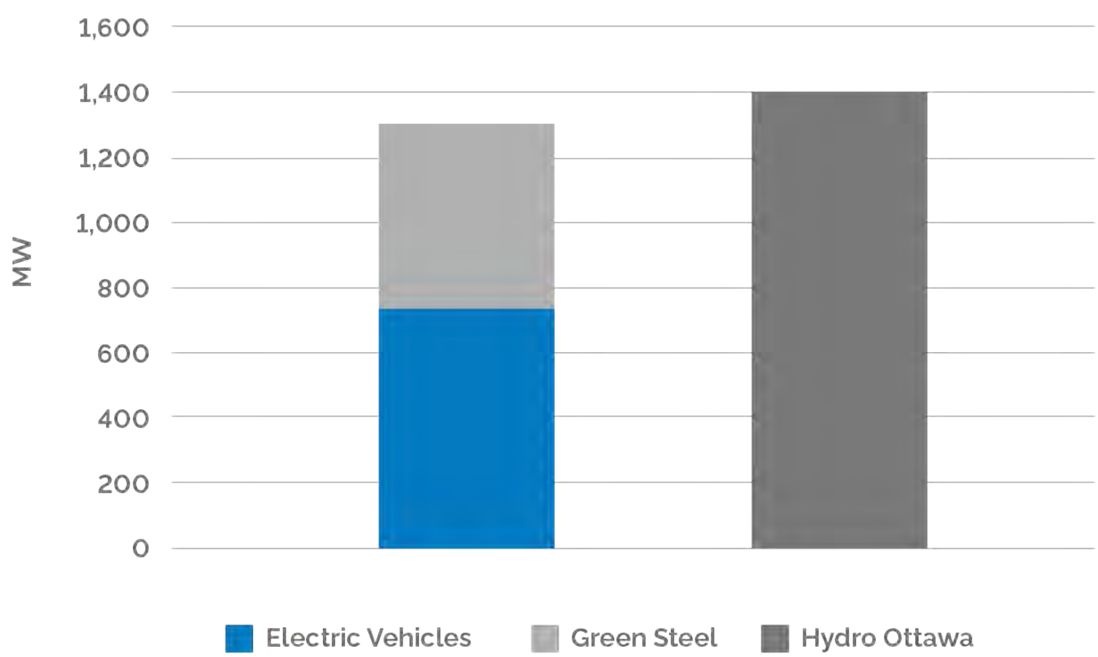
In April 2024, the government also welcomed a $15 billion investment by Honda Canada to create Canada's first comprehensive electric vehicle supply chain, located in Ontario.

This large-scale project will see four new manufacturing plants in Ontario. Honda will build an innovative and world-class electric vehicle assembly plant – the first of its kind for Honda Motor Co. Ltd. – as well as a new stand-alone battery manufacturing plant at Honda's facilities in Alliston. To complete the supply chain, Honda will also build a cathode active material and precursor (CAM/pCAM) processing plant through a joint venture partnership with POSCO Future M Co., Ltd. and a separator plant through a joint venture partnership with Asahi Kasei Corporation. Once fully operational in 2028, the new assembly plant will produce up to 240,000 vehicles per year.

Ontario has also secured major investments in clean steelmaking projects in Hamilton and Sault Ste. Marie with ArcelorMittal Dofasco and Algoma Steel. These once-in-a-generation investments will transform the province into a world-leading producer of green steel.

These investments will also boost the robust auto parts supply chain and skilled workforce in communities with deep roots in steel manufacturing and help meet the global demand for low-carbon auto production.

*Figure 7: Projected Industrial Electricity Demand*



Ontario's technology sector is also continuing to grow. The IESO reports that data centres will consume a total of 137 MW of demand by the end of 2026, roughly equal to adding the demand of the city of Kingston to the grid. The rise of artificial intelligence (AI) and the data centres that power advances in computing could also lead to significant increases in demand on energy grids. AI applications, particularly large language models, require substantial computational power, leading to higher energy consumption.

Several sectors are in a period of significant growth driven by longer-term trends that are driving higher demand. For example, greenhouse expansions and increased lighting requirement have resulted in the IESO projecting consumption from the agriculture sector to grow from around 5 TWh to 8 TWh by 2050, which is a 60 per cent increase, the equivalent of adding another City of London to the grid. Mining processes in northern Ontario will electrify some of their processes to improve efficiency and reduce emissions. The IESO is projecting this to contribute towards already robust industrial growth in the forecast.

At the same time, Ontario's population is expected to grow by almost 15 per cent or two million people by the end of this decade.

All of these homes will require reliable electricity, especially as households increase their consumption by electrifying heating, cooling and transportation. The IESO states that electricity demand from electric vehicles is forecast to grow from about 1.6 TWh in 2025 to 41.6 TWh in 2050, an average annual growth rate of about 13.9 per cent.

Access to other fuels and sources of energy such as natural gas also continue to be critical to attracting new jobs in manufacturing, including the automotive industry and agriculture. Natural gas currently makes up almost 40 per cent of Ontario's overall energy mix and is the dominant fuel used for heating, serving about 3.8 million customers. All of this growth highlights the need for Ontario to move forward with plans for bolder action and investment to ensure the energy system supports continued growth.

# Our Vision: An Economy Powered by Affordable, Reliable and Clean Energy

## 1. Planning for Growth

Challenge: Ontario needs to plan for electricity, natural gas and other fuels to ensure that the province's energy needs are anticipated and met in a coordinated way.

### Introduction

Ontario cannot afford to repeat the same mistakes as past governments and must move forward with energy planning that considers all sources of energy to meet our growing energy needs.

This is a complex undertaking that will require comprehensive view of how all energy sources are used across the economy. The pace of change has accelerated, and this is likely to continue as Ontario becomes home to new technologies and growing industries. Ontario must also plan for localized needs in certain communities and regions, changing the way power must flow across the province.

To meet this challenge, Ontario needs planning and regulatory frameworks that support building infrastructure and resources quickly and cost-effectively, and in a way that continues to promote Indigenous leadership and participation in energy projects. There is also a need to accelerate processes for building out the last mile to connect new homes and businesses supported by growth-oriented energy agencies to keep Ontario open for business.

### Integrated Energy Resource Planning

Building the energy infrastructure necessary to power Ontario's future is a complex undertaking that requires the highest level of strategic energy planning and coordination.

The Ontario government can lead Canada in implementing an integrated energy planning process to ensure it is making the most cost-effective decisions for a clean energy future. This all-energy approach to planning would consider electricity, natural gas, hydrogen and other fuels. An integrated energy resource plan would help manage change and growing demand by providing clear signals and long-term confidence to the sector and investors.

By planning for all sources of energy and ensuring the energy system supports key goals such as building housing and attracting investment, Ontario will have a pathway to achieving its energy vision. The pace of change will be driven by the emergence of new major energy users, such as in the electric vehicle supply chain and data centres, and by individual decisions made by consumers with respect to how they power their homes, vehicles and businesses. Maintaining customer choice as a driving principle of Ontario's vision requires regular planning to ensure that energy sources are available for customers when they need them.

A key component of any integrated plan is a forecast for energy needs into the future. The IESO will continue to play a critical role in providing forecasts that drive investments in the electricity system. However, there is a need to enhance energy forecasting and coordinated planning so that there is greater alignment across energy sources.

### Electrification and Energy Transition Panel

Recognizing the need for enhanced planning, the Ontario government established the independent Electrification and Energy Transition Panel to advise on high-value short, medium and long-term opportunities.

Appointed panel members included **Chair David Collie, Dr. Monica Gattinger** and **Chief Emerita Emily Whetung.**

To support the work of the panel and provide key inputs into long-term energy planning for the province, the government also commissioned an independent cost-effective energy pathways study to support the panel and understand how Ontario's energy sector can support electrification and the energy transition.

The panel's final report, *Ontario's Clean Energy Opportunity,* was released earlier this year following a comprehensive engagement with stakeholders and Indigenous communities. This work has informed Ontario's vision and affirmed the need for a first-of-a-kind integrated energy plan to coordinate the entire energy sector to help power a clean and growing economy.

### Priorities for Integrated Energy Resource Planning:

- Ontario's energy sector needs to be guided by an integrated energy resource plan that ensures the province has the affordable power needed for a clean and growing economy.
- Integrated planning needs to be done on a regular cycle and incorporate all energy sources and input from Indigenous communities, the public and energy sector stakeholders.
- The IESO, as well as electricity and natural gas utilities need to coordinate their planning frameworks around shared, evidence-based forecasts for gas all types of energy use.
- The OEB will need to consider outputs from planning in its adjudication and other regulatory activities.
- There is a need for independent, external advice into the energy planning framework, including advice on the integration of energy planning with other government objectives, such as housing and economic development.
- Electricity forecasts must consider scenarios that reflect high growth, driven by population and GDP growth, accelerated electrification and evolving technological trends.
- There is a need for greater electricity and natural gas coordination in system planning that is informed by evidence-based forecasts that take the pace of electrification into account.

## Electricity Generation

The province recognizes the challenge ahead and will continue to build on its successful planning for baseload resources and procurement processes to bring additional energy resources online so they support growth. That approach will ensure Ontario can take advantage of the full range of generation technologies and leverage competitive approaches wherever possible to keep electricity affordable.

To extend its clean energy advantage, Ontario needs to consider how more clean energy sources can be brought online.

### Baseload Nuclear and Hydroelectricity: The Backbone of Ontario's Clean Electricity System

Ontario's plan will prioritize clean and reliable baseload electricity from nuclear and hydroelectricity. These resources have provided more than 75 per cent of the province's electricity over the last 20 years.

Ontario will continue to advance work on new nuclear and hydroelectric generation, which requires much longer lead times and long-term certainty than other resources but could serve the province well into the next century. This includes generational decisions to start pre-development and preparation for deployment of new nuclear – including work at Bruce Power and on the Darlington New Nuclear Project.

### Priorities for Electricity Generation:

- Ontario's plan will prioritize clean and reliable baseload electricity from nuclear and hydroelectricity.
- Meeting the accelerating pace of growth will require:
    - A cadence of competitive long-term procurements that ensures new energy resources are built at lowest cost, thereby protecting ratepayers and taxpayers.
    - Securing energy from existing resources through competitive procurements, refurbishments and specialized programs.
    - Exploring the strategic value of other long-life assets, such as long-duration storage.
- Ontario's energy procurements must continue to advance economic reconciliation with Indigenous communities by including opportunities for Indigenous leadership and participation in generation projects, supported by community capacity funding and access to financing.

## Electricity Transmission

As the province builds out new generation, the transmission network must be expanded to get that energy where it needs to go. And as the system grows and new businesses set up shop, the system must move quicker – including enhanced transmission planning and pre-development activities so lines can proceed to construction quickly with the support of sector participants, municipalities and Indigenous communities.

### Priorities for Electricity Transmission:

- Ontario must continue to expedite the development of transmission infrastructure including through enhanced transmission planning and pre-development activities.
- Customers wishing to connect to the transmission system or electrify their processes need to be able to do so efficiently and at costs that are fair for everyone.
- New transmission infrastructure development needs to continue to advance reconciliation with Indigenous communities through early engagement and by creating opportunities for Indigenous leadership and partnership, economic participation and capacity building.

## Last Mile Connections

Building new housing means there will be many new customers to connect to the energy system. An efficient connections framework that reduces barriers to customers will be essential to ensure the energy system supports growth.

The ability to attract investment and realize the province's housing goals will also depend on having dynamic, responsive and high-performing utilities as well as supportive and efficient regulatory processes.

### Priorities for Last Mile Connections:

- There is a continued need for a regulatory framework that ensures last mile connections to homes and businesses are completed quickly to support growth.
- Ontario must look for opportunities to enhance information sharing and communication between developers, utilities, municipalities and local Indigenous communities to help address connection timeline challenges.
- Ontario's utilities need to continue to be high-performing and cost-efficient in their work to connect new homes and businesses to the province's grid.

## Natural Gas

Natural gas currently makes up almost 40 per cent of Ontario's overall energy mix and is the dominant fuel used for heating, serving about 3.8 million customers. Natural gas is a vital component of Ontario's energy mix and the province's first integrated energy resource plan.

It fulfills diverse roles across the industrial, residential, commercial and agricultural sectors. It is also a critical component of the province's electricity generation mix to maintain reliability: increased electricity generation through natural gas can help reduce province-wide emissions by supporting cost-effective electrification in other sectors.

There is a need for the energy system to adapt to the pace of change so consumers continue to be empowered to make choices about their energy sources. That will require coordination among natural gas utilities, electricity utilities and the IESO to manage energy system costs and ensure reliability as significant investments in energy infrastructure are needed to support a growing and evolving economy. This coordination would ensure that electricity resources keep pace with demand as an increasing number of consumers switch energy sources over time, while reducing the risk of stranding assets before the end of their useful life.

Over the long-term, an economically viable natural gas network can also support the integration of clean fuels to reduce emissions, including renewable natural gas (RNG) and low-carbon hydrogen. Consumers in Ontario already have access to programs offered by Enbridge or non-utility suppliers (e.g., Bullfrog Power) to voluntarily add RNG to their gas supply. Pilot projects are also underway to increase low-carbon hydrogen production and use, including projects supported through the Hydrogen Innovation Fund.

Carbon capture and storage is another emerging technology that could reduce emissions generated by the continued use of natural gas by large industrial consumers. Ontario is committed to developing and implementing a framework to regulate commercial-scale geologic carbon storage projects in the province.

Going forward, Ontario will include a Natural Gas Policy Statement in its integrated energy resource plan to provide clear direction on the role of natural gas in Ontario's future energy system.

### Priorities for Natural Gas:

- The build out of a cleaner and more diversified economy must be paced according to the needs of homes, businesses and economic investment, including the need to keep energy costs competitive, not ideologically driven.
- There is a need for an economically viable natural gas network to support a gradual energy transition, to attract industrial investment, to drive economic growth, to maintain customer choice and ensure overall energy system resiliency, reliability and affordability.
- Ontario must continue to seek opportunities to support energy efficiency, clean fuels and carbon capture to reduce emissions from the natural gas system while lowering energy costs for consumers.
- The OEB should continue to play its role as the natural gas system's regulator to protect consumers, to ensure utilities can invest in their systems and earn a fair return, and to enable the rational expansion and maintenance of the system.

## Other Fuels

Ontario's first integrated energy resource plan will also consider other fuels including petroleum-based fuels (e.g., gasoline), propane and low-carbon fuels that make up just under 40 per cent of Ontario's energy mix.

Petroleum products are critical fuels to move goods and people and heat homes. They also have non-energy applications in the manufacturing and agricultural sector where electric options are not currently commercially available.

While the first oil well in North America was drilled in Oil Springs, near Sarnia, the province's crude oil production now accounts for less than one per cent of Ontario's total oil demand today. Ontario relies almost entirely on imported crude oil delivered from Western Canada and the United States by interprovincial and international pipelines to four refineries in Ontario. Ontario's refineries supply approximately 78 per cent of Ontario's refined product demand, with Quebec and the U.S. supplying the remainder.

Gasoline, diesel and jet fuel currently dominate the fuels sector, however, exciting and innovative advances in low-carbon fuels such as RNG, ethanol, renewable diesel, biodiesel and low-carbon hydrogen continue to provide sustainable alternatives. These may also provide a more cost-effective pathway than electrification to reduce emissions for some types of energy use.

### Priorities for Other Fuels:

- Ontario needs to continue to ensure a secure supply of fuels and fuel transportation infrastructure through its work with industry stakeholders, the federal government, potentially impacted Indigenous communities, and other provincial governments.
- Further work is needed to explore opportunities to increase production of clean fuels and identify end-use applications where these clean fuels can be best deployed.
- There is a need for enhanced integration of all fuels in planning and coordination with other provincial strategies, such as for transportation, agriculture, forestry and the environment.

## Indigenous Leadership and Participation

Indigenous communities are already leaders and key partners in Ontario's energy sector, with many First Nation and Métis communities owning or partnered on energy projects across the province. Those communities see immediate and lasting economic benefits that come from their participation in energy projects, including stable streams of revenue and knock-on benefits such as increased opportunities for Indigenous businesses, job creation and skills development.

### Canada's Largest Indigenous-Led Infrastructure Project

The Wataynikaneyap Power Transmission Project, which is expected to reach substantial completion later this year, will be the largest Indigenous-led infrastructure project in Canada and connect over 18,000 people in northwestern Ontario to a clean, reliable and affordable supply of electricity. Wataynikaneyap Power is owned by 24 First Nation communities in partnership with FortisOntario and Algonquin Power & Utilities Corporation and provides direct benefits for those communities far beyond ending their reliance on dirty and costly diesel energy.

For example, the 100 per cent Indigenous-owned Opiikapawiin Services LP has led skills development and training to support Indigenous employment and participation throughout the project, with 51 training programs administered and over 600 Indigenous individuals completing training.

These partnerships also offer mutual benefits by creating opportunities for the province and energy proponents to learn from Indigenous leaders, elders and community members and ensure that energy developments consider potential impacts to Aboriginal and treaty rights. Indigenous participation in energy projects can ultimately help to get critical infrastructure built on time with better outcomes, such as reduced environmental impacts and employment and other economic benefits for Indigenous communities.

### Priorities for Indigenous Leadership and Participation:

- Early and meaningful engagement and consultation with Indigenous communities on energy planning and major energy projects is critical to building out our energy system.
- Continued capacity funding and support for Indigenous ownership and participation in energy projects is needed, through programs like the provincial Aboriginal Loan Guarantee Program and the recently expanded IESO Indigenous Energy Support Program.
- Energy procurements need to incorporate the value of Indigenous leadership and participation by building on existing incentives and engagement requirements.
- Ontario must continue to build meaningful relationships with Indigenous communities and organizations and seek regular dialogue on regional and territorial energy interests underpinned by capacity support and relationship agreements.
- Indigenous representation is critical to ensuring there are Indigenous voices at the table on provincial energy matters.

## Local, Regional and Interjurisdictional Energy Planning

Ontario has empowered municipalities as part of the energy planning process. This includes through the important role of municipal support in the energy procurement process.

Going forward, there is value in municipalities taking on a greater leadership role in energy planning in their communities because many are experiencing rapid growth. When communities are growing, municipal planning and energy planning needs to work in lockstep to support the build out of housing and business development.

There are also opportunities to work with Ontario's neighbouring jurisdictions and the federal government on energy issues that cross borders. This includes codified approaches to electric vehicle charging and to expanding electricity interties.

System planning needs to be done in a way that serves all Ontarians and ensures no one is left behind. An integrated planning approach will consider how energy choices can support healthy, diverse populations and communities.

### Priorities for Local, Regional and Interjurisdictional Energy Planning:

- There is a need for strengthened local energy planning, including through municipal guidance, support and capacity building – such as through the Municipal Energy Plan program, as well as better alignment with the province's integrated energy planning process and other planning processes.
- There is a need for Ontario to work with the IESO, the OEB, Indigenous communities and stakeholders to continue to improve the Regional Planning Process so it supports coordination with natural gas planning, supports high growth regions and appropriately integrates municipal energy plans.
- There is an opportunity to work with neighbouring jurisdictions on interjurisdictional infrastructure planning (e.g., electricity interties).

## Growth-Oriented Agencies

The IESO and the OEB are essential partners in achieving Ontario's vision for an affordable and clean energy system. Ontario's forecasted growth will increasingly challenge its agency partners to undertake their planning and approval functions rapidly and transparently.

In recent years, significant work has been undertaken at both the IESO and the OEB to modernize processes, support innovation and prepare for growth and electrification. This focus on continuous improvement is essential and must be accelerated to ensure planning and approvals can best serve high-growth areas and support Ontario's ability to attract future investment.

Ontario's energy sector participants, businesses and the public expect that energy planning decisions are made at the pace of growth. They also expect that planning information, such as growth forecasts and available system capacity, is informed by the best available data, which is updated regularly and made publicly available to support investment decisions. Regional planning cycles, particularly in high-growth regions, must be responsive to the pace of change.

### Priorities to Support Growth-Oriented Agencies:

- There is an opportunity for the IESO to continue to build on its forecasting and planning framework to ensure there are tools to support high-growth regions.
- Ontario needs its energy agencies to continue to seek opportunities to expedite their approvals, decisions and other processes while continuing to prioritize reliability and affordability.
- Businesses need greater and more timely access to information on the state of the system to support connection decisions.
- The OEB should continue to seek opportunities to improve the efficiency of its independent adjudication and make greater use of non-adjudicative tools in regulating the sector.

# 2. Affordable and Reliable Energy

## Challenge: Energy affordability must be prioritized as Ontario's energy system expands to meet demand and support economic growth.

Affordability is central to customers' having fair access to energy and the affordability of clean electricity is essential to driving customer choices to electrify. Customers need the right tools and data to manage their energy consumption so that they can make informed choices for their homes and transportation. This Ontario government will offer an alternative to any federal carbon tax, which maintains the pace of growth in the province while not applying new costs and makes energy available and affordable so that customers choose to switch.

### Ontario's Alternative to a Carbon Tax

Affordability is a critical concern for families across Canada, but the carbon tax is only making life more expensive.

On April 1, 2024, the federal government increased the carbon tax by 23 per cent making it more expensive to build a new home, for a family to put gas in their car, put food on the table or buy everyday essentials.

Today the carbon tax adds 17.57 cents per litre to gasoline prices in Ontario. That will rise to about 30 cents by 2030. The carbon tax is adding about $350 on average to a household's annual natural gas bills.

The Government of Ontario has been clear in its opposition to the carbon tax. Ontario's first-of-a-kind integrated energy resource plan will invest in the province's prosperity and its energy systems to give residents and businesses affordable choices to use clean energy. This is Ontario's alternative to the carbon tax.

#### Priorities for Ontario's Alternative to a Carbon Tax:

- Ontario will never include a carbon tax in its plan.
- For Ontario's vision for a clean energy economy to be achieved, people and industry must have choice over their energy sources and no one can be left behind.
- Ontario will meet its 2030 emissions target with clean, affordable and reliable power that supports families and businesses as they make the choice to move away from higher emitting sources of energy, without a costly and unnecessary carbon tax.

### Helping Ontarians Save through Energy Efficiency

As Ontarians choose to electrify their homes and businesses, there is an opportunity to install more efficient appliances and smarter controls to save energy and participate in programs and initiatives that benefit Ontario's energy system as a whole.

Ontario can build on accomplishments to date by expanding energy efficiency programs and empowering customers through energy data and tools, to lower costs for families and businesses. The government intends to unveil new energy efficiency programs aimed at helping families and businesses reduce their bills and save energy later this year.

### Priorities for Helping Ontarians Save through Energy Efficiency:

- There is an opportunity to expand energy efficiency to help consumers lower their energy costs and to help offset investments in new, more expensive electricity infrastructure.
- Households, businesses and institutions would benefit from easier-to-access information about their energy use to make informed decisions about their building's energy performance, through streamlined processes that protect consumer information.
- Encouraging and supporting consumers who want to reduce their overall energy use to save money and lower emissions should be a continued priority over the long term.

## Supporting Electric Vehicles (EVs)

As more families and businesses make the switch to electric vehicles, the government must ensure that electricity remains reliable and affordable, and that Ontarians can find public chargers when and where they need them.

There is a continued need to improve access to and remove roadblocks for building affordable EV charging infrastructure (e.g., public stations, home, work and fleet charging) and allow for greater choice, access and safe uptake of electric mobility options across Ontario.

### Priorities for Supporting EVs:

- Ontario's regulatory framework for electricity must continue to support the efficient integration of EVs and growing EV adoption.
- Any opportunity to reduce barriers to the build out of affordable EV charging infrastructure must be explored to support greater choice, access and uptake of EVs.
- Strong collaboration across government is needed to support continued growth in private and public EV charging infrastructure.

## Empowering Energy Consumers to Participate in the Grid

Industrial, commercial and residential customers are increasingly leveraging technologies like solar photovoltaic panels, batteries, electric vehicles, thermal storage, smart thermostats and electric water heaters to manage their energy use, reduce their energy costs, and provide back-up power or heat. These small-scale energy systems that generate, store or manage electricity close to where they are used, in homes and businesses, are referred to as distributed energy resources (DER). These DER systems can also be directly connected to the distribution grid and provide energy and other services to local or bulk grid.

Giving customers more ways to participate in the grid, with a focus on creating new ways for families and businesses to save money while reducing province-wide energy demand, benefits us all. As the grid evolves with the increasing adoption of DER, the policy framework too must evolve to support customer choice and reduce barriers to all types of DER investments that can support local energy needs and improve the efficient utilization of these resources within the energy system.

### Priorities for Empowering Energy Consumers to Participate in the Grid:

- There is an ongoing opportunity to expand the use of DERs where it is cost-effective and beneficial to meeting local and system needs.
- Customers would benefit from increased opportunities for customer-sited generation and storage that offers bill savings or resiliency benefits for residential, small business and farm customers.
- There are opportunities to examine broader implementation of projects piloted by OEB and IESO that have demonstrated customer, local and system benefits.
- There is an opportunity to improve collection and sharing of DER data to the mutual benefit of LDCs, the OEB, the IESO, customers and DER developers.

## Grid Modernization

Distribution grids throughout the province will need to modernize, utilizing and integrating innovative technologies that facilitate active monitoring of their systems, while building better resiliency to changes in weather patterns and extreme weather events.

Ontarians expect that their LDC will serve them safely, reliably, cost effectively and that over time they will steadily improve. These expectations must be met as LDCs concurrently confront the necessary modernization of the grid, improve the grid's overall resilience, and directly support Ontario's economic development and housing targets. The government continues to support voluntary consolidation in the electricity distribution sector which can help local distribution companies be better positioned to support Ontario's electrification needs and improve services for customers well into the future.

By providing further clarity on what are considered grid modernization activities, the province can help LDCs make prudent investments to support increasing energy demand.

### Priorities for Grid Modernization:

- Ontario recognizes the need to work with the OEB to provide greater clarity and predictability to LDCs so that they can modernize their infrastructure to provide the energy and services that ratepayers need into the future.
- There are opportunities for the government, IESO and the OEB to accelerate implementation of grid innovation projects that provide ratepayer value.
- There is a need to strengthen the governance and accountability of LDCs to improve operational efficiencies, increase reliability, and support investments necessary for the increasing energy demand.

## Grid Resiliency

As concerns about climate change and extreme weather events such as flooding, wildfires and ice storms rise, building grid resiliency across the province is essential to Ontario's economic growth and energy future.

Ontario has released the Vulnerability Assessment for Ontario's Electricity Distribution Sector which summarizes anticipated extreme weather risks to Ontario's electricity distribution networks. Further actions can be taken by working with agencies and LDCs to strengthen Ontario's grid and ensure the energy system is prepared to respond to future extreme weather events and cyber threats.

### Priorities for Grid Resiliency:

- There is a need to build capacity in the sector to conduct risk assessments to drive more effective action in making Ontario's grid resilient.
- Ontario must ensure that reducing impacts on vulnerable populations is a key consideration in resiliency and adaptation planning in the sector.
- Any efforts to enhance grid resiliency must be done in an economically efficient manner that prioritizes value for customers.

## Programs for Energy Affordability

Maintaining affordable electricity pricing will be critical to driving customer decisions to electrify their lives with clean energy.

Several energy support programs are in place, including broad support programs like the Ontario Electricity Rebate. The government also offers targeted supports to people who need it most. Earlier this year the government expanded access to the Ontario Electricity Support Program (OESP) by increasing the eligibility thresholds by up to 35 per cent.

To maintain the sustainability of the programs and ensure support is available to those who need it most, it will be crucial to monitor the costs and designs of these programs, and to adjust where necessary.

### Priorities for Programs for Energy Affordability:

- Cost-effective, competitive and technology-agnostic procurement of energy resources is an enduring priority to manage system costs.
- There is a continued need for targeted supports to those who need it most, including low-income households.
- Ontario's suite of electricity rate mitigation programs must provide continued stability and predictability for families and businesses.

## Affordable Home Heating

Not all communities have access to the same sources of energy for home heating. While more than 70 per cent of homes are heated with natural gas, many still rely on other more expensive sources including propane and home heating oil.

The government is providing families with multiple options to help make home heating more affordable.

To help families and businesses in rural Ontario transition off higher-cost and higher-emission forms of energy, the government provides support through the Natural Gas Expansion Program (NGEP). Work is underway to explore how to continue these efforts and provide financial support and affordable home heating to more communities.

This is complemented by programs like the former Clean Home Heating Initiative (CHHI), the Energy Affordability Program and the HomeEnergySaver program, which provide opportunities for households to complement their existing heating source with an electric heat pump.

### Priorities for Affordable Home Heating:

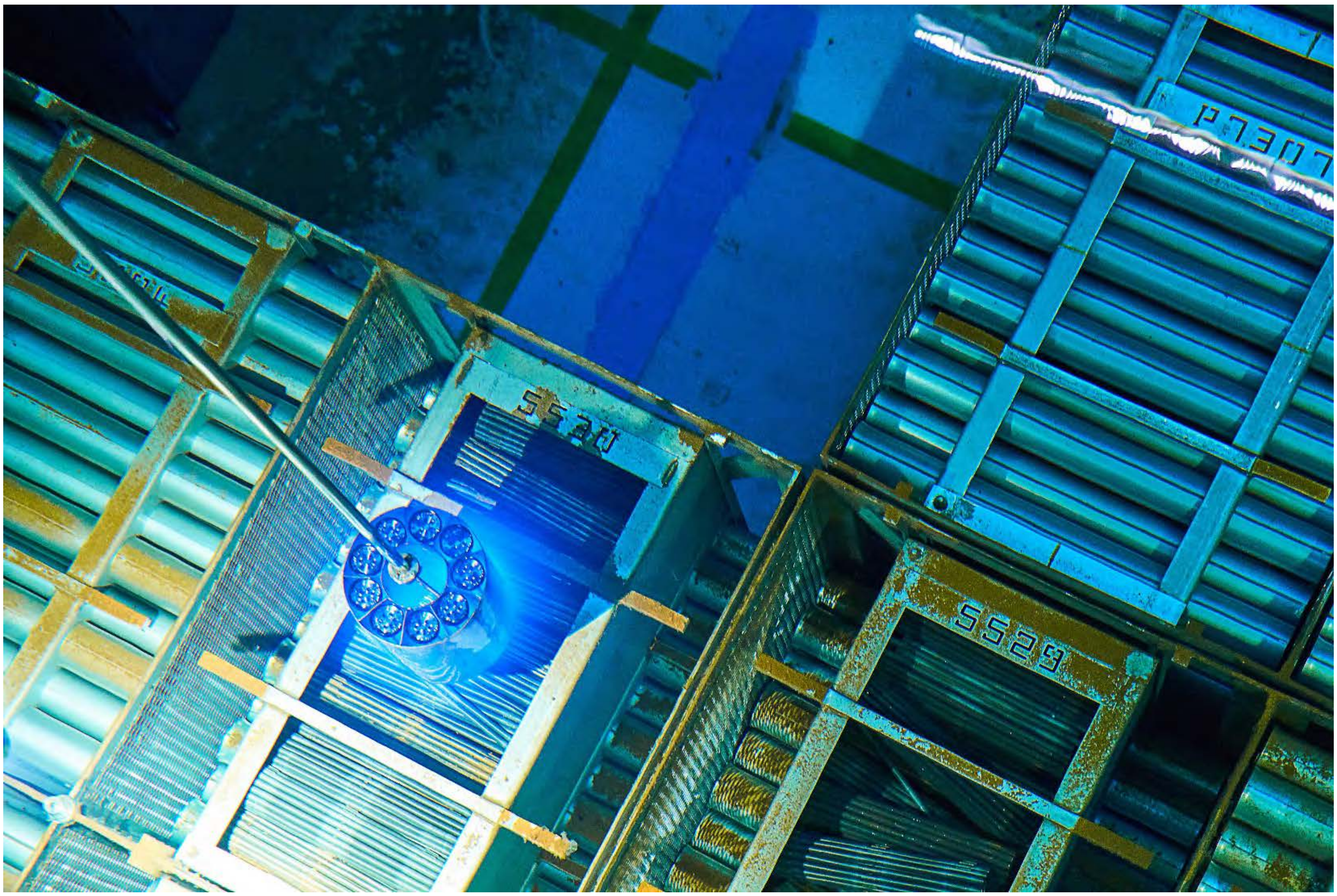
- There is a need to ensure Ontarians have affordable options for home heating from different energy sources.
- Affordable home heating options should be available that take advantage of Ontario's clean electricity system, such as through heat pumps and other new technologies as well as energy efficiency measures.

# 3. Becoming an Energy Superpower

## Challenge: Ontario has the opportunity to use our competitive advantage to export clean energy and technology across the continent and beyond.

Energy will be a cornerstone of the province's economic strategy and success. Creating stability of supply through prudent investments and planning will foster an environment in which companies from around the world can be assured that Ontario is an ideal place to conduct business for generations to come.

That also creates an additional opportunity where other jurisdictions recognize that as they seek to meet their own clean energy goals that Ontario can be a partner in their work.



## Exporting Power and Expertise

Ontario has a diverse, world-class and clean electricity system, powered by nuclear, hydroelectricity, solar, wind, natural gas, biomass, biogas and electricity storage. Ontario also has a proven ability to build complex energy projects on time and budget, benefitting from strong agencies that have led to a cost effective and highly reliable energy system.

That combination positions Ontario as a continental leader in clean energy. Across North America, many jurisdictions and businesses are establishing clean energy targets for their electricity grids that will require historic investments and lengthy lead times to accomplish. Ontario is well-placed to step in and play a critical role as a clean energy leader and help these jurisdictions reduce their GHG emissions.

### History of Electricity Imports and Exports

Electricity imports and exports are a normal part of the operation of the electricity market. Ontario's electricity system currently has 26 interties connected with five neighbouring jurisdictions: three with Manitoba, eleven with Quebec, one with Minnesota, four with Michigan and seven with New York, with a total nominal transfer capacity of approximately 6,000 megawatts (MW).

Since 2006, Ontario has been a net exporter to these jurisdictions. In 2023, Ontario scheduled net exports of 12.4 terawatt-hours (TWh), an increase of 29 per cent from the 9.6 TWh net exports of 2022. For context, Ontario exported 11 per cent of its total generation in 2023.

Those exports have not always been in the province's favour. Historically, Ontario experienced periods of Surplus Baseload Generation (SBG), which occurred when output from baseload generation resources exceeded Ontario demand. These periods of SBG, which typically occurred overnight in the spring and fall, required the IESO to use market mechanisms such as exports or economic curtailment of certain resources to balance supply and demand.

SBG can result in low, or even negative, wholesale prices for participants in the electricity market. This is because hydro and nuclear generation are considered "non-dispatchable," meaning they have limited to no flexibility to reduce energy production. Therefore, they will offer very low prices so that their production is the last to be curtailed. According to the IESO, for a sample period between 2016 and 2020, between 5 to 9 per cent of all exports were sold at $0 per megawatt-hour or less. Although the surplus power was made available to consumers, there was often limited or low demand at the time this power was available.

### Future Opportunities for Electricity Exports

The IESO is forecasting that Ontario energy demand will increase by 75 per cent over the course of the next 25 years. Ontario will position itself to not just meet that domestic demand, but where it makes sense for the province, and is in the best interests of ratepayers, to exceed it.

As part of the exploration of further export opportunities, the IESO has been tasked with supporting the development of an export strategy that generates new revenue streams and creates good jobs here at home. The IESO's analysis will act as the foundation for any plan development on an export strategy. As Ontario's electricity system grows, expanding the interconnections with neighbouring jurisdictions will be important to help provide operational flexibility and mitigate risks. Many of Ontario's interconnected jurisdictions have an anticipated shortfall or a clean energy commitment to meet (i.e., New York, Maryland and Illinois) or both (i.e., Michigan and Minnesota) but are currently reliant on resources like coal which could be replaced with clean energy imports. The government believes that pursuing further export opportunities would require increasing generation.

The IESO's analysis will include:

- A scoping of the generation resources and transmission infrastructure required to serve the best opportunities to Ontario and its ratepayers while also being able to deliver the desired exports to neighbouring jurisdictions; and
- An assessment of the required commercial, market pathways and mechanisms to capture cost effective export opportunities.

The province currently has robust transmission interties with neighbouring provinces and states and trades electricity every day as a core function of the Ontario market. As the province builds out its competitive advantage in energy, there may be greater opportunities to leverage trade to benefit Ontario ratepayers and provide clean energy to other jurisdictions.

It would also improve the resilience of the Ontario energy system by expanding the option to import power when needed to meet peak demand, such as during extreme weather events.

Ontario has experience negotiating export arrangements with its neighbours. For instance, Ontario currently has an agreement in place to "swap" 600 MW of capacity on a seasonal basis with Hydro Quebec, and the IESO has a separate agreement with New York's ISO (NYISO) to facilitate imports and exports of capacity between the two jurisdictions.

Additional opportunities might exist in these and in other neighbouring jurisdictions to which Ontario is interconnected. Both NYISO and Midcontinent ISO (MISO), which serves most of the US midwestern states, are projecting significant shortfalls in the years ahead. There may be opportunities for firm export agreements with these jurisdictions that could offset the costs of building new generation in Ontario and actually help reduce bills for Ontario families while also creating good jobs.

Ontario's generators and electricity traders already participate extensively in the US through wholesale electricity markets. In addition, both NYISO and MISO administer capacity auctions in their jurisdictions. Ontario would not participate in long-term export commitment unless a firm revenue agreement was in place to protect and actually drive value for Ontarians.

Any export deals with other jurisdictions would need a lead counterparty in Ontario, such as a generator or the IESO, as well as firm transmission rights to ensure delivery when the power is needed. With support from the province, the province believes Ontario's market participants are both sophisticated and capable of executing such deals.

## Leadership in Nuclear Projects and Innovation

The province is a leader in nuclear projects and technology. The Canada Deuterium Uranium (CANDU) reactor technology used in our current fleet was developed in Ontario and has been exported around the world. Our multi-billion-dollar nuclear industry supports 65,000 jobs across the province and is helping our nuclear operators, OPG and Bruce Power, to deliver complex refurbishment projects at their stations on-time and on-budget. Ontario companies are also sharing their know-how beyond our borders through partnerships in the United States and Europe. The nuclear sector is advancing innovation in nuclear and non-nuclear applications, such as SMRs and medical isotopes that are used for diagnosing and treating life-threatening diseases and sterilization of medical equipment around the world.

### Priorities for Exporting Power and Expertise:

- Ensure Ontario families directly benefit from any agreement to export power through lower bills, enhanced revenue streams for the province and good-paying, local jobs.
- Ontario has an opportunity to work with the IESO and other sector partners to explore cost-effective opportunities to increase trade with neighbouring jurisdictions, including through new or expanded interties.
- Ontario's nuclear leadership in SMRs, large-scale nuclear technology and other nuclear innovations, could continue to create new export opportunities, drive economic growth and create jobs across the province.
- Ontario's nuclear fleet can continue to advance key opportunities in research, development and production of medical isotopes and make Ontario a global isotope superpower.

## Next Steps

Ontario intends to take early actions towards meeting the challenges laid out in this document in the weeks and months ahead. These actions would build on steps already taken since the release of *Powering Ontario's Growth*.

The priorities articulated in this document will also guide Ontario's first integrated energy resource plan. In building the plan, input from the public, stakeholders and Indigenous communities will help to inform the actions needed to achieve our energy vision.

Your feedback will be carefully reviewed as Ontario moves forward with launching its first integrated energy resource plan in 2025.

# Glossary of Terms

### Baseload generation
Baseload generators are typically designed to run at a constant rate and typically include nuclear and large hydroelectric facilities.

### Bioenergy
Energy produced from organic material sources. Sources for bioenergy generation can include agricultural residues, food-process by-products, animal manure, waste wood and organic kitchen waste.

### Distributed Energy Resources (DERs)
Resources that generate energy, store energy, or control load and are directly connected to the distribution system or located behind a customer's meter.

### Electric Vehicle (EV)
Any vehicle that is partially or fully powered by electricity and plugs in to recharge. They can reduce fossil fuel consumption and emissions.

### Energy Efficiency
Any conservation program or action which reduces the amount of electricity consumed or reduces the amount of power drawn from the electricity grid.

### Independent Electricity System Operator (IESO)
The provincial entity that delivers key services across the electricity sector, including managing the power system in real-time, planning for the province's future energy needs, enabling conservation and designing a more efficient electricity marketplace to support sector evolution.

### Local Distribution Company (LDC)
A utility that owns and/or operates a distribution system that delivers electricity to consumers.

### Megawatt (MW)
A standard unit of power that is equal to 1 million watts (W) used to depict peak energy demand or generation capacity. For instance, a nuclear reactor can generate approximately 800-900 MW while a large wind turbine can generate up to 3 MW. Peak demand for the city of Ottawa is on the order of 1,500 MW.

### Megawatt-hour (MWh) / Terawatt-hour (TWh)
Measure of energy demand (and generation) over time. Note: 1 million MWh is equal to 1 terawatthour (TWh).

### Ontario Energy Board (OEB)
The Ontario Energy Board (OEB) is the independent agency that regulates Ontario's electricity and natural gas sectors in the public interest.

### Peak Demand
Peak demand or, peak load or on peak are terms describing a period in which demand for electricity is highest. In Ontario, the annual electricity power peak demand usually occurs in the mid to late afternoon during a hot, humid, sunny weekday in July or August.

### Small Modular Reactor (SMR)
Nuclear reactors that are significantly smaller and more flexible than conventional nuclear reactors and can be factory-built. Small Modular Reactors (SMRs) could operate independently or be linked to multiple units, depending on the required amount of power.

**Ministry of Energy**

Office of the Minister

77 Grenville Street, 10th Floor
Toronto ON M7A 2C1
Tel.: 416-327-6758

**Ministère de l'Énergie**

Bureau du ministre

77, rue Grenville, 10e étage
Toronto ON M7A 2C1
Tél. : 416-327-6758

Ontario

MC-994-2023-864

November 29, 2023

Mr. Glenn O'Farrell
Acting Chair
Ontario Energy Board
2300 Yonge Street, 27th Floor
PO Box 2319
Toronto ON M4P 1E4

Dear Mr. O'Farrell:

In keeping with my responsibilities as Minister of Energy, I am writing to provide you with a renewed Letter of Direction, including updates on the government's priorities for the energy sector and my expectations for the Ontario Energy Board (OEB) in the upcoming three-year business planning period.

It has been three years since the OEB's modernized governance structure came into effect on October 1, 2020. The modernization transition period ended last year, and the OEB's board of directors now exercises its full authority under the *Ontario Energy Board Act, 1998* (OEBA).

As I noted in my letter last year, the transition period has ended at a time when the OEB's role as energy regulator has never been more important. Electrification and the transition to cleaner energy sources requires strong, proactive thought leadership from the OEB in consultation with the sector.

Since my previous letter of direction, much has changed in the Ontario energy sector. The Independent Electricity System Operator (IESO) released its *Pathways to Decarbonization* report in response to my request to evaluate a moratorium on new natural gas generation in Ontario, and to develop an achievable pathway to decarbonization in the electricity system. In response, the government released our *Powering Ontario's Growth* plan for the energy system, in which Ontario leverages its clean energy grid to promote electrification and job creation while continually enhancing reliability, resiliency, and customer choice. The *Electrification and Energy Transition Panel* has engaged broadly with stakeholders, Indigenous communities and energy sector experts and will be submitting their recommendations to me this fall.

In previous letters, I noted specific initiatives that I viewed as critical to the health of Ontario's energy sector and necessary for the OEB to prioritize. This work remains both relevant and necessary to the OEB's overall modernization agenda and should continue. I appreciate the OEB's efforts to advance these initiatives through its business plans.

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I would also like to thank the OEB for supporting the province's Broadband expansion into rural Ontario, and the implementation of both the Green Button initiative and the Ultra-Low Overnight Electricity Rate to further support energy affordability.

*Priorities to Advance in the Near-Term*

At this time, I wish to highlight areas where I will be expecting significant progress over the coming year. Previous mandate letters have referred to some of these priorities; however, given the urgent need to advance these items in the next 12 months, I am providing the OEB with my expectations:

**Powering Ontario's Growth:** In July 2023, Ontario released *Powering Ontario's Growth*, outlining actions the province is taking to meet increasing demand for electricity driven by strong economic growth and electrification through the 2030s and 2040s. These actions, which include zero-emissions electricity generation, long-duration storage, and transmission lines will ensure a reliable, clean, and affordable energy system for the future. I expect the OEB will work with my Ministry on a number of initiatives that support implementation of our plan.

- **Housing, Transportation and Job Creation:** Our government has ambitious goals to build at least 1.5 million new homes, new highways, subways and improved rail transportation, and has also been successful in attracting new jobs to the province, particularly in critical minerals, electric vehicles and battery manufacturing. With this in mind, it is critical that the OEB ensures that Ontario's electricity and gas transmission and distribution systems are built to support these goals in a timely manner, while protecting ratepayers. Achieving this goal requires timely decision-making, well scrutinized costs and a regulatory environment with certainty for proponents. I encourage the OEB to review electricity infrastructure unit costs in the electricity sector and potential models for cost recovery that could help to ensure infrastructure costs are kept low and are not a barrier to growth in our province. I also ask that the OEB review its electricity distribution system expansion connection horizon and revenue horizon direction to ensure that the balance of growth and ratepayer costs remain appropriate. Please **report back on this review in June 2024**. I also ask the OEB to keep in mind the impact that delays and uncertainty can have on Ontario families, businesses and Indigenous communities, as well as economic investment in the province. Lastly, while the Ministry awaits the Electrification and Energy Transition Panel's report on energy sector governance and supporting a cost-effective energy transition, we must be mindful of affordability impacts to customers while maintaining resilient energy systems. The OEB should continue to ensure that the needs of all customers are considered in its work, and that access to electricity and natural gas in an affordable manner remains central to decision-making.

- **Facilitating Innovation within Ontario's Regulatory Framework:** The OEB's 2023 Stakeholder Survey results showed that stakeholders believe the OEB can do more to facilitate innovation in the energy sector. I acknowledge recent

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announcements, such as the OEB's Innovation Sandbox Challenge, are headed in the right direction. Nevertheless, as electrification and energy transition progresses, the OEB should continually explore how to maximize its flexibility to facilitate innovation within the existing regulatory framework. The OEB should continue to collaborate with the IESO, Ministry officials and sector stakeholders in this regard. Innovation in both gas and electric sectors is critical to meeting our goals of meeting future energy demand and reducing emissions.

The government's vision for a clean energy grid that attracts investment and creates jobs while continually enhancing reliability, resiliency and customer choice will require utilities to make new investments. For decades utilities' remuneration has been based on traditional capital infrastructure deployment; the OEB should consider if this approach remains the most cost-effective model.

Last year, I asked the OEB to host workshops to explore how they could enable low-carbon investments while protecting consumers' interests to deliver on the government's vision. As we look at how to remunerate utilities appropriately through this transition, I ask the OEB to take the next steps and consider what changes may be required to ensure timely investment is being made to support the right outcome. A report back on this work should incorporate a review of models deployed in other jurisdictions. These findings could be incorporated in your **Benefit-Cost Analysis Framework for Addressing Electricity System Needs or through another report. I look forward to being updated on progress in this area and would ask for a report back by September 2024.**

- **Distributed Energy Resources (DERs) and Future Utility Business Models:** Distributed Energy Resources (DERs) will become critical connectors in a clean energy economy. While electrification can be a growing challenge for ageing infrastructure, it can also be a significant opportunity for innovation across the electricity system. DERs, through behind-the-meter and front-of-meter technologies, can be used as cost-effective alternatives to conventional electricity infrastructure. They can also help consumers better manage their energy costs and capitalize on investments like roof-top solar, electric vehicles (EVs), batteries, and responsive air conditioners and water heaters. I expect the OEB will continue to work with the Ministry and the IESO toward the Ministry's stated commitment of developing and assessing local and market opportunities for DERs, including through alternative energy business models. The OEB should work closely with my Ministry to examine the potential regulatory landscape for future utility business models.

- **Electricity and Natural Gas Conservation:** Ontario continues to be a leader in energy conservation with a long history of delivering results and savings for ratepayers. While program coordination between roughly 60 local distribution electricity companies and Enbridge has historically been challenging in this space, the IESO and Enbridge have been successful in providing a one-window program for income tested customers since electricity conservation program delivery was

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centralized with the IESO. Building on this success, we must now turn our attention to delivering this same level of service to non-income tested residential customers. I ask that the OEB consult with the IESO and Enbridge and **report back in April 2024** on how electricity and natural gas low-income and residential programs could be delivered through a single window.

On July 24th, 2023, my Ministry launched a public and stakeholder engagement on the scoping of future energy efficiency and conservation frameworks. This engagement was intended to inform my Ministry's work on developing a proposed path forward for electricity conservation programming. In August, my Ministry received a report from an IESO - Local Distribution Companies CDM Working Group on an enduring approach to joint delivery of energy efficiency programming. This report proposes a new approach to funding energy efficiency programs with both bulk and local system benefits and has the potential to increase the contribution of energy efficiency in the province as a low-cost, non-emitting resource. In response to this report, in cooperation with the IESO - LDC CDM Working Group, I will be looking for OEB staff to provide guidance on an appropriate cost-sharing mechanism from the Global Adjustment and distribution rates that is grounded on the principle of beneficiary pays in order to advance the development of a funding stream for "Stream 2" CDM activities. I am also looking to the OEB to provide guidance on what changes would be needed to the OEB's CDM Guidelines to reduce barriers to LDC conservation activities as outlined in the Working Group's initial report.

With respect to natural gas energy efficiency programming, I was pleased to see the launch of new natural gas conservation programs for the 2023-2025 period this past year. As the OEB begins planning for future natural gas energy efficiency programming that would take effect in 2026, I continue to look to the OEB to ensure Ontario electricity and natural gas ratepayer interests are protected and that Ontario takes every opportunity to generate deeper retrofits, more energy savings, and greater emissions reductions while ensuring natural gas costs remain affordable, stable and predictable.

- **Electric Vehicles (EVs):** Last year, I asked the OEB to provide guidance to electric utilities when planning for EVs to ensure that Ontario is ready for the expected growth in this sector, and I appreciate the guidance provided last December. With the growth in home building across the province, it is important local distribution companies plan and build with the expectation that electrical demands per household will grow. I also directed the OEB to consider distribution rates for EV charging (including demand charges).

  I strongly endorse further advancement of this file. I acknowledge the continued progress that the OEB has made this year, including completing a survey of distributors and charging companies, commissioning and receiving the Electricity Delivery Rates for EV Charging Report and continued work to review connection policies, including the recent announcement to expand the scope of the DER Connections Review to include identifying opportunities for enhancements to guidance on system readiness for EV charging connections.

…/cont'd

The EV Delivery Rates Report considered two opportunities to support EV charging update: a time-of-use rate and a low load factor rate. I appreciate that the OEB has worked both internally and with stakeholders to consider these opportunities. Based on that work, I expect to provide guidance to the OEB on next steps early in the new year.

I also believe it is time for the OEB to take the results of its work and provide clear direction to the sector, including considering service standards, a standardized process with enforceable timelines for connecting EV charging infrastructure, and publicly available electric distribution capacity information. I also call on the OEB to go beyond consolidating existing requirements for distributors. Distributors need to be able to pre-invest in their infrastructure to support potential EV demand.

- **Intervenor Process:** In 2021, the Top Quartile Regulator Report identified that "regulators need access to external expertise and a spectrum of perspectives." The value of intervenors, however, is significantly diminished when the remuneration structure incentivizes the creation of issues or duplicates effort. Effective case management can mitigate this risk, but additional controls are necessary. In 2021-22, Ontario's 5.3 million electricity and natural gas customers paid $4.4 million to fund the Ontario Energy Board's intervenor process. I encourage the OEB to continue its work reviewing the current intervenor processes and to identify opportunities to improve regulatory efficiency and consequently reduce regulatory burden. This should include, but is not limited to, consideration around a designated consumer advocate and capping intervenor costs. I ask that the OEB **report back in September 2024** with its plan to implement reforms.

- **Performance Measurement Framework Review:** As noted in previous letters, my expectation is that future business plans include a robust performance measurement framework to demonstrate how outcomes will be measured and how they advance the OEB's strategic goals. As the province's energy regulator, it is critical that the OEB hold itself to the highest standard of performance, including setting performance measures that clearly define and measure how it is having a direct impact on sector outcomes. I look forward to the upcoming mid-term review, based on two years of results plus baseline, for inclusion in the 2024-2027 Business Plan. As stated in my letter approving last year's business plan, my team is available to assist with this work throughout the review process to ensure that we have a common understanding of the outcomes the OEB is looking to achieve to evaluate its performance and how it will use the outcomes measured to improve its performance. I also endorse the OEB's proposal to launch a small working group with the sector to provide feedback on goals and performance measurement.

- **Red Tape Reduction:** In response to my letter of direction last year, the OEB committed to a target of 5% burden reduction over the baseline measured by the Ministry of Energy in 2018 by March 2026. Please continue to keep my Ministry informed of your progress, highlight your progress in the next Business Plan, and provide me with updates, when requested, for the Ministry of Red Tape Reduction's annual reporting.

…/cont'd

- **<u>Distribution Sector Resiliency, Responsiveness, and Cost Efficiency:</u>** Thank you for delivering the OEB's report on improving distribution sector resiliency, responsiveness, and cost efficiency on June 30, 2023, as requested in last year's letter of direction. Recognizing that the OEB is well-positioned to work directly with utilities to protect customers in a changing climate, I endorse several actions you have identified in the report and ask that the OEB begin to develop and implement policies that will require local distribution companies to:

    - Provide details and report on their current storm recovery planning and preparation activities;
    - Incorporate climate resiliency into their asset and investment planning;
    - Engage in a regular assessment of the vulnerabilities in their distribution system and operations in the event of severe weather;
    - Prioritize value for customers when investing in system enhancements for resilience purposes; and
    - Satisfy minimum targets for customer communication regarding interruptions and restoration of service following major weather events and measure and report on restoration of service following such events.

On those items related to climate resiliency and responsiveness listed above, I expect the OEB to make significant progress on development and implementation of its recommendations by the end of 2024. I also ask that the OEB post its DRRCE report to me online by year end.

I also endorse the OEB's proposals related to cost-effective service, including:

- Reviewing whether the accounting and associated rate treatment of shared services should be adjusted and develop guidance on a fair approach to cost and risk apportionment for shared service provision;
- Engaging stakeholders in a scoping exercise at the outset of the Mergers, Acquisitions, Amalgamations and Divestiture (MAADs) review;
- Reviewing elements in its incentive rate-setting mechanisms and examining distributors' spending patterns to identify where changes or incremental incentives are warranted; and
- Developing a performance incentive regime that considers aspects such as customer service, resilience, or managing peak loads to defer distribution system needs, and working with the sector to develop principles, generic designs, and other criteria for performance incentives.

I recognize that those items related to cost-effectiveness are multi-year endeavours. Over the next 12 months, I expect that the OEB begin this work and provide stakeholders with a clear plan for the timing of any reforms.

The remaining proposals, including a peer-review committee and sectoral coordination, will require additional consideration within government. My team and I will continue to engage the OEB on those recommendations you provided for government action.

…/cont'd

- **Electrification and Energy Transition Panel:** I will soon receive advice on how to support the transformation of the energy sector from the Electrification and Energy Transition Panel (Panel), chaired by David Collie. I appreciate the OEB's thoughtful advice to the Panel throughout its engagement process. Ontario must take action to facilitate the energy transition to secure the associated environmental and economic development benefits, while ensuring investments across the energy system are made in the interest of ratepayers. I will keep you informed on any further initiatives to be incorporated into the OEB's subsequent business plans as a result of the Panel's advice.

*Next Steps and Broad Government Priorities for Agencies*

Please continue to provide quarterly updates on the OEB's progress against these expectations. If, in executing any of these priorities, the OEB identifies that legislative or regulatory barriers are preventing it from delivering on expectations, please engage my Ministry with analysis and potential solutions to resolve the barriers. As I have made clear throughout this letter, the Ministry is prepared to take action to ensure the OEB has the tools and authority it needs to advance the government's vision for the energy sector and prepare Ontario for a clean energy future.

Appended to this letter you will find the government-wide priorities for Board-governed agencies for 2024-25. It is important that the Board's goals, objectives, and strategic direction continue to align with our government's priorities and direction. As part of the Government of Ontario, agencies are expected to act in the best interests of the people of Ontario and ensure that they provide value for money to taxpayers. Agencies are also required to adhere to government policies and directives.

My thanks to you, the Board of Directors, and all OEB executives and staff for the work they do in support of Ontarians. I look forward to receiving the forthcoming business plan and continuing to work together in support of a clean, reliable, and affordable electricity system.

Sincerely,

Todd Smith
Minister

c: David Donovan, Chief of Staff to the Minister of Energy
Palmer Lockridge, Deputy Chief of Staff to the Minister of Energy
Jason Fitzsimmons, Deputy Minister of Energy
Susanna Zagar, Chief Executive Officer, Ontario Energy Board

## APPENDIX: Government of Ontario Priorities for Board-Governed Agencies

1. **Competitiveness, Sustainability and Expenditure Management**
   - Operating within the agency's financial allocations.
   - Identifying and pursuing opportunities for revenue generation, efficiencies and savings through innovative practices, and/or improved program sustainability.
   - Complying with applicable direction related to accounting practices and supply chain centralization, including leveraging Supply Ontario's bulk purchasing arrangement and working with Supply Ontario on strategic procurement initiatives.
   - Complying with realty interim measures for agency office space.
   - Leverage and meet benchmarked outcomes for compensation strategies and directives.

2. **Transparency and Accountability**
   - Abiding by applicable government directives and policies and ensuring transparency and accountability in reporting.
   - Adhering to accounting standards and practices, and responding to audit findings, where applicable.
   - Identifying appropriate skills, knowledge and experience needed to effectively support the board's role in agency governance and accountability, and providing the Minister with annual skills matrices to ensure boards have qualified appointees.
   - Reviewing and updating agency KPIs annually to ensure efficiency, effectiveness and sustainability.

3. **Risk Management**
   - Developing and implementing an effective process for the identification, assessment and mitigation of agency risks, including cyber security, and any future emergency risks.

4. **Workforce/Labour Management**
   - Optimizing your organizational capacity to support the best possible public service delivery, including redeploying resources to priority areas, where needed.
   - Supporting the implementation of the Community Jobs Initiative (CJI) by identifying opportunities to relocate new or existing agencies to lower cost communities across Ontario (as per MBC Realty Directive, s. 5.4), as applicable.
   - Aligning Human Resource and Accommodations strategies with OPS directives and policy.
   - Adhering to TB/MBC labour and bargaining mandates.
   - Prudently and efficiently managing operational funding and workforce size.

5. **Diversity and Inclusion**
   - Developing and encouraging diversity and inclusion initiatives by promoting an equitable, inclusive, accessible, anti-racist and diverse workplace.
   - Adopting an inclusion engagement process to ensure all voices are heard to inform policies and decision-making.

6. **Data Collection**, **Sharing and Use**
    - Improving how the agency uses data in decision-making, information sharing and reporting, to inform outcome-based reporting and improve service delivery.
    - Increasing data sharing with Supply Ontario when applicable regarding procurement spending and planning, contract arrangements and vendor relations to support data-driven decision-making.

7. **Digital Delivery and Customer Service**
    - Exploring and implementing digitization for online service delivery to ensure customer service standards are met.
    - Using a variety of approaches or tools to ensure service delivery in all situations.

STATEMENT

# Ontario Government Standing Up for Families and Businesses

Province will introduce legislation that, if passed, would reverse an Ontario Energy Board decision that would lead to skyrocketing costs on new homes

**December 22, 2023**

Energy

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**TORONTO -** Today, Todd Smith, Minister of Energy, released the following statement:

“Our government was elected with a mandate to rebuild Ontario’s economy as we keep costs down for people and businesses and build the homes our growing province needs.

“I am extremely disappointed in yesterday’s split decision by the Ontario Energy Board to reduce the amortization period for the cost of installing new natural gas connections for homes. This decision, which would mean costs that are normally paid over 40 years would be owed in full up front, could lead to tens of thousands of dollars added to the cost of building new homes. At a time when Ontario, like the rest of Canada, is already dealing with the difficult headwinds of high interest rates and inflationary pressures, the Ontario Energy Board’s decisions would slow or halt the construction of new homes, including affordable housing. We will not stand for this.

“In response, I will use all of my authorities as Minister to pause the Ontario Energy Board’s decision. At the earliest opportunity, our government will introduce legislation that, if passed, would reverse it, so that we protect future homebuyers and keep shovels in the ground.”

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**Media Contacts**

**Michael Dodsworth**
Office of the Minister of Energy
Michael.Dodsworth@ontario.ca

**Natasha Demetriades**
Communications Branch
Natasha.Demetriades@ontario.ca
416-327-3855

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NEWS RELEASE

# Ontario Keeping Energy and Housing Costs Down

New legislation would help build housing faster and save families and businesses money

**February 22, 2024**

Energy

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**TORONTO –** Today, the Ontario government introduced legislation that, if passed, would reverse a December 2023 decision by the Ontario Energy Board (OEB) that would have significantly increased the costs of building new homes across the province. Reversing this decision will prevent an average of $4,400 being added to the price of new homes, or tens of thousands of dollars being added to the price of a home in rural Ontario.

"Since day one our government has taken action to lower energy costs, including by cancelling the previous government's cap-and-trade carbon tax and cutting the gas tax," said Todd Smith, Minister of Energy. "While previous governments implemented schemes that led to skyrocketing energy prices, we're using every tool in our toolbox to keep costs down for people and businesses. The *Keeping Energy Costs Down Act* will protect future homebuyers from increased costs and keep shovels in the ground on critical infrastructure projects."

The *Keeping Energy Costs Down Act, 2024* would, if passed, give the province authority to reverse the OEB decision to require residential customers and small businesses to pay 100 per cent of the cost of new natural gas connections upfront. These costs would have previously been paid over forty years. Once the government introduces a Natural Gas Policy Statement, a recommendation of the *Electrification and Energy Transition Panel*'s final report, it will require the OEB to consider this issue again.

The government will also appoint a new chair of the OEB this spring with the expectation that the board and commissioners conducts appropriate consultation – in line with the proposed legislative requirements - before reaching decisions that support the objective of an affordable, reliable, and clean energy system.

"Natural gas will continue to be an important part of Ontario's energy mix as we implement our pragmatic plan to invest in and bring online more clean nuclear energy," added Minister Smith. "Unlike the previous government, which saddled families with sky-high hydro bills, our government is taking a thoughtful approach that keeps costs down for people and businesses and delivers energy security."

To ensure that future decisions reflect and support the priorities of the people of Ontario, the *Keeping Energy Costs Down Act* would require the OEB to conduct broader engagement to ensure impacted organizations and sectors have an opportunity to participate in proceedings. It would also enable the government to require the OEB to conduct a separate hearing on any matter of public interest.

The proposed legislation would also maintain the existing treatment of gas transmission projects that are critical to the province's economic growth by ensuring new customers do not have to incur upfront financial contributions and update the OEB's Leave to Construct process to respond to concerns raised by municipalities around supporting critical housing projects and local economic development initiatives.

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**Quick Facts**

- The Ontario's *Electrification and Energy Transition Panel's* (EETP) final report, Ontario's Clean Energy Opportunity was released on January 19, 2024.
- The EETP's final report stated that natural gas is an important resource, fulfilling three essential and distinct functions in Ontario's energy system today as a fuel for electrical power generation, space and water heating, and industrial and agricultural industries.
- 3.8 million households in Ontario currently use natural gas for home heating, representing about 70 per cent of Ontario households.
- Currently natural gas meets 39 per cent of Ontario's energy demands, while electricity meets 21 per cent.
- Through the Clean Home Heating Initiative Ontario is deploying hybrid heating solutions which pair electrically powered air source heat pumps with a conventional natural gas furnace to reduce energy costs and emissions by leveraging Ontario's world-class clean electricity grid. Maintaining access to natural gas ensures reliable access to heat on the coldest days of the year.
- To help Ontario families and businesses keep costs down, the government extended the gas and fuel tax rate cuts through to June 30, 2024. Along with the rate cuts previously in place, this extension is expected to save households $260 on average since the cuts were first implemented in July 2022.

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**Additional Resources**

- The Keeping Energy Costs Down Act

**Manage energy costs for your home**

Learn about programs and credits to reduce your energy bills.

**Manage energy costs for your business**

For large to small businesses, manage your energy costs through one of these programs.

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**Related Topics**

**Environment and Energy**
Learn more about how Ontario protects and restores wildlife and the environment. Includes information on conservation and the electricity system. Learn more

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**Media Contacts**

**Palmer Lockridge**
Minister's Office
palmer.lockridge@ontario.ca

**Natasha Demetriades**
Communications Branch
Natasha.Demetriades@ontario.ca
416-327-3855

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Legislative Assembly of Ontario

Assemblée législative de l'Ontario

1ST SESSION, 43RD LEGISLATURE, ONTARIO
2 CHARLES III, 2024

# Bill 165

*(Chapter 10 of the Statutes of Ontario, 2024)*

## An Act to amend the Ontario Energy Board Act, 1998 respecting certain Board proceedings and related matters

**The Hon. T. Smith**
Minister of Energy

| | |
|---|---|
| 1st Reading | February 22, 2024 |
| 2nd Reading | February 28, 2024 |
| 3rd Reading | May 15, 2024 |
| Royal Assent | May 16, 2024 |

# EXPLANATORY NOTE

*This Explanatory Note was written as a reader's aid to Bill 165 and does not form part of the law. Bill 165 has been enacted as Chapter 10 of the Statutes of Ontario, 2024.*

The Bill makes various amendments to the *Ontario Energy Board Act, 1998*.

A new section 28.8 authorizes the Minister, subject to the Lieutenant Governor in Council's approval, to issue directives requiring the Ontario Energy Board (Board) to hold a generic hearing to determine any matter respecting natural gas or electricity over which it has jurisdiction that the directives specify. The directives may address various matters respecting the hearing, including setting out timelines and procedural requirements. A directive may apply with respect to a matter that is the subject of an ongoing proceeding before the Board, but may not apply with respect to a matter that was determined by a final order of the Board if fewer than two years have elapsed since the order was made. The section provides for the rules that apply if an ongoing proceeding is affected by a directive. A definition of "generic hearing" is added to section 3 of the Act, and section 19 of the Act is amended to specify that the Board has authority to hold generic hearings under subsection 19 (4).

A new section 36.0.1 provides for the setting of a revenue horizon by regulations made under the Act. "Revenue horizon" is defined as the number of years of presumed revenue that is used in determining specified matters relating to the natural gas distribution system. The revenue horizon is used for the purposes of section 36 of the Act (respecting Board orders relating to the transmission, distribution and storage of gas). The new section also provides authority for regulations to be made that require the Board to hold a hearing to determine revenue horizons, and governing the hearings. A revenue horizon determined by the Board applies instead of one specified by the regulations. The Bill provides that section 36.0.1 is to be repealed on the earlier of January 1, 2029 and a day to be named by proclamation of the Lieutenant Governor.

A new section 96.2 authorizes the Minister, subject to the Lieutenant Governor in Council's approval, to issue directives providing that if a proposed natural gas transmission or dual-purpose transmission and distribution line specified by the directive is the subject of an application under section 90 of the Act for the Board's leave to construct the line, the Board is subject to certain requirements in making its determination, set out in subsection 96.2 (1). A directive may apply with respect to an application that is already before the Board. The new section also provides authority for the Minister, subject to the Lieutenant Governor in Council's approval, to issue a directive respecting any order made by the Board between February 22, 2024 and December 31, 2024 in which the Board refuses to grant leave to construct a proposed natural gas transmission or dual-purpose transmission and distribution line, or grants it subject to specified conditions. Such a directive may require the Board to rescind the order and hold a new hearing, taking into account the requirements set out in subsection 96.2 (1).

For each of the new sections, the Bill provides that the exercise of powers under the sections are not subject to any duties of procedural fairness that would otherwise apply under the *Statutory Powers Procedure Act* or otherwise in law.

In addition to adding the new sections, the Bill re-enacts sections 4.4 and 4.4.1 of the Act, which require the Board to establish one or more processes for obtaining stakeholder input and providing for the representation of consumer and other interests, respectively. The re-enacted sections are expanded to apply to the gas context, as well as to provide authority for the making of regulations to specify or add to the list of persons whom the Board must contemplate in establishing processes. Related regulation-making powers are set out.

Finally, the Bill amends section 95 of the Act. Currently, section 95 provides that the Board may make orders in special circumstances exempting persons from the leave to construct requirements in sections 90 and 92 of the Act. Section 95 is amended to additionally require the Board to make an order exempting persons from these requirements if the Board is satisfied that the circumstances prescribed by the regulations have been met. Related regulation-making powers are set out.

**Bill 165** **2024**

# An Act to amend the Ontario Energy Board Act, 1998 respecting certain Board proceedings and related matters

**Preamble**

The Government of Ontario:

Is working to keep costs down, make life more affordable for Ontario workers and their families and grow the economy.

Is committed to building at least 1.5 million homes by 2031 in order to keep the dream of homeownership alive.

Is powering Ontario's economic growth with a diverse energy mix that will provide reliable, affordable energy for households and businesses for decades to come.

Supports good decision-making by the Ontario Energy Board that is informed by broad consumer and stakeholder input and that supports the priorities of the people of Ontario, including keeping energy costs down.

Therefore, His Majesty, by and with the advice and consent of the Legislative Assembly of the Province of Ontario, enacts as follows:

**1 Section 3 of the *Ontario Energy Board Act, 1998* is amended by adding the following definition:**

"generic hearing" means a hearing held under subsection 19 (4) to determine one or more matters pertaining to multiple persons or entities whose activities are regulated by the Board under this Act; ("audience générique")

**2 Sections 4.4 and 4.4.1 of the Act are repealed and the following substituted:**

**Processes, stakeholder input**

**Electricity industry**

**4.4** (1) The Board shall establish one or more processes by which electricity consumers, distributors, generators, transmitters, any other persons who have an interest in the electricity industry and any other persons who may be prescribed by the regulations may provide advice and recommendations for consideration by the Board.

**Gas industry**

(2) The Board shall establish one or more processes by which gas consumers, gas distributors, gas transmitters, storage companies, any other persons who have an interest in the gas industry and any other persons who may be prescribed by the regulations may provide advice and recommendations for consideration by the Board.

**Specified persons**

(3) If the regulations so provide,

(a) a process under subsection (1) shall include such electricity consumers, distributors, generators, transmitters, other persons who have an interest in the electricity industry or prescribed persons as the regulations specify;

(b) a process under subsection (2) shall include such gas consumers, gas distributors, gas transmitters, storage companies, other persons who have an interest in the gas industry or prescribed persons as the regulations specify.

**Processes, representation of consumer and other interests**

**4.4.1** (1) The Board shall establish one or more processes by which the interests of electricity consumers, gas consumers and any other persons who may be prescribed by the regulations may be represented in proceedings before the Board, through advocacy and through any other modes of representation provided for by the Board.

**Specified persons**

(2) If the regulations so provide, a process under subsection (1) shall include such electricity consumers, gas consumers or prescribed persons as the regulations specify.

**3 (1) Subsection 19 (4) of the Act is amended by striking out "under section 28 or otherwise" and substituting "under section 28 or 28.8 or otherwise under this or any other Act".**

**(2) Section 19 of the Act is amended by adding the following subsection:**

**Same**

(4.1) Subsection (4) includes the determination of matters at a generic hearing.

**4 The Act is amended by adding the following section:**

**Directives, requirement to hold generic hearing (natural gas, electricity)**

**28.8** (1) In this section,

"ongoing proceeding" means, in respect of a proceeding before the Board, a proceeding in which the Board has not yet made a final order.

**Same**

(2) The Minister may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council requiring the Board to hold a generic hearing to determine any matter respecting natural gas or electricity over which it has jurisdiction that the directives specify.

**Same**

(3) A directive issued under subsection (2) may specify,

(a) timelines for conducting the hearing;

(b) the manner in which the hearing may or must be conducted;

(c) matters, information or documents, including documents written or issued by the Government or by a minister or ministry of the Crown, that the Board must consider in conducting the hearing and making its determination; and

(d) any other matter respecting the hearing or its conduct that the Minister considers appropriate.

**Exception**

(4) Subsection (2) does not apply with respect to a matter if, at the time the directive would be issued, fewer than two years have elapsed since the matter was determined by a final order of the Board, regardless of whether the order was appealed.

**Application to ongoing proceedings**

(5) Subsection (2) may apply with respect to a matter that is the subject of an ongoing proceeding before the Board.

**Same, effect**

(6) If a directive is issued respecting a matter that is the subject of an ongoing proceeding before the Board,

(a) the Board shall not make any order in the ongoing proceeding with respect to the matter, and shall sever the matter from the ongoing proceeding to the extent possible; and

(b) except as provided under clause (a), the ongoing proceeding shall continue to the extent possible.

**Procedural fairness does not apply**

(7) Neither the issuance or approval of a directive under this section nor any action taken by the Board to implement or comply with it is subject to any duty of procedural fairness, including any requirement to provide notice, reasons or an opportunity to make submissions.

**Same**

(8) Subsection (7) applies despite the *Statutory Powers Procedure Act* and any other law.

**Conflict**

(9) In the event of a conflict between a directive under this section and the *Statutory Powers Procedure Act*, the rules made by the Board under section 25.1 of that Act or an order of the Board or other instrument or document made or issued under this Act, the directive prevails to the extent of the conflict.

**Publication**

(10) A directive issued under this section shall be published in *The Ontario Gazette*.

**Not a regulation**

(11) For greater certainty, Part III (Regulations) of the *Legislation Act, 2006* does not apply to directives issued under this section.

**5 (1) The Act is amended by adding the following section:**

**Revenue horizon (natural gas)**

**36.0.1** (1) In this section,

"consumer" means a person who uses natural gas in Ontario for the person's own consumption; ("consommateur") "natural gas distribution system" means a system for distributing natural gas in Ontario by hydrocarbon line, as defined in Part VI, and includes any structures, equipment or other things used for that purpose; ("réseau de distribution de gaz naturel")

"revenue horizon" means the number of years of presumed revenue that is used for the purposes of section 36 in determining,

(a) the economic feasibility of,

(i) a new consumer connection to the natural gas distribution system, or

(ii) an increase in the capacity of the natural gas distribution system, and

(b) the amount, if any, of a contribution in aid of construction required from a consumer in relation to a connection or increase described in clause (a). ("horizon de revenu")

**Mandated revenue horizon**

(2) The revenue horizon for the purposes of section 36 shall be the number of years specified by the regulations, except as otherwise provided by this section.

**Board may be required to make determination**

(3) If the regulations so provide, the Board shall hold a hearing to determine revenue horizons for the purposes of section 36, in accordance with the regulations.

**Same**

(4) Regulations made for the purposes of subsection (3) may provide for,

(a) timelines for conducting the hearing;

(b) the manner in which the hearing may or must be conducted, including requiring that it be conducted as a generic hearing;

(c) matters, information or documents, including documents written or issued by the Government or by a minister or ministry of the Crown, that the Board must consider in conducting the hearing and making its determination; and

(d) any other matter respecting the hearing or its conduct that the Lieutenant Governor in Council considers appropriate.

**Board determination prevails**

(5) If the Board determines a revenue horizon for a period under subsection (3), that revenue horizon applies for the period instead of the revenue horizon specified by the regulations.

**Board to implement**

(6) The Board shall take such steps under this Act as are necessary to implement the revenue horizon set out in subsection (2) or, if applicable, determined under subsection (3).

**Limitation**

(7) The Board shall not make any determinations respecting revenue horizons for the purposes of section 36, except as provided by regulations made for the purposes of subsection (3).

**Same**

(8) The Minister shall not issue a directive under section 28.8 respecting the determination of revenue horizons for the purposes of section 36.

**Procedural fairness does not apply**

(9) No action taken by the Board to implement or comply with a regulation made under this section is subject to any duty of procedural fairness, including any requirement to provide notice, reasons or an opportunity to make submissions, despite the *Statutory Powers Procedure Act* or any other law.

**Same**

(10) For greater certainty, nothing about the making of a regulation under this section, or the circumstances in which it is made, shall be interpreted as imposing a duty of procedural fairness on the exercise of a regulation-making authority.

**Conflict**

(11) In the event of a conflict between a regulation made under this section and the *Statutory Powers Procedure Act*, the rules made by the Board under section 25.1 of that Act or an order of the Board or other instrument or document made or issued under this Act, the regulation prevails to the extent of the conflict.

**Same**

(12) Subsection (11) does not apply with respect to an order of the Board made before December 21, 2023.

**Regulations**

(13) The Lieutenant Governor in Council may make regulations for the purposes of this section,

(a) specifying numbers of years for the purposes of subsection (2), including, for greater certainty, specifying different numbers with respect to different classes of consumers;

(b) requiring and governing a hearing under subsection (3).

**(2) Section 36.0.1 of the Act, as enacted by subsection (1), is repealed.**

**6 Section 91 of the Act is repealed and the following substituted:**

**Application for leave to construct hydrocarbon line or station**

**91** (1) Any person may, before constructing a hydrocarbon line to which subsection 90 (1) does not apply or a station, apply to the Board for an order granting leave to construct the hydrocarbon line or station.

**Applies to exempted hydrocarbon lines**

(2) For greater certainty, a person who has obtained an exemption from the requirements of subsection 90 (1) may make an application under subsection (1) of this section in respect of the exempt hydrocarbon line.

**7 Section 95 of the Act is repealed and the following substituted:**

**Exemption, subs. 90 (1) or 92 (1)**

**95** (1) The Board may, if in its opinion special circumstances of a particular case so require, make an order exempting any person from the requirements of subsection 90 (1) or 92 (1) without a hearing.

**Same, prescribed circumstances**

(2) The Board shall, with or without a hearing, make an order exempting a person from the requirements of subsection 90 (1) or 92 (1) if the Board is satisfied that the circumstances prescribed by the regulations have been met.

**8 (1) The Act is amended by adding the following section:**

**Directives, applications re certain natural gas lines**

**96.2** (1) The Minister may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council providing that if the construction of a proposed natural gas transmission or dual-purpose transmission and distribution line specified by the directive is the subject of an application under section 90,

(a) the Board shall accept that it is in the public interest for such natural gas consumers as are specified in the directive to bear the full cost of the line; and

(b) the Board may not require a contribution in aid of construction or surcharge to be paid by a natural gas consumer who will be connected to or served by the line.

**Same**

(2) A directive issued under subsection (1) may specify one or more proposed natural gas transmission or dual-purpose transmission and distribution lines or classes of lines.

**Ongoing applications**

(3) If it so provides, a directive issued under subsection (1) applies with respect to an application made but not finally determined before the day the directive is issued.

**Directives re certain Board orders**

(4) If, during the period referred to in subsection (5), the Board makes an order refusing to grant leave to construct a proposed natural gas transmission or dual-purpose transmission and distribution line or an order granting leave to construct such a line subject to a condition that a contribution in aid of construction by natural gas consumers is required, the Minister may issue, and the Board shall implement, a directive that has been approved by the Lieutenant Governor in Council,

(a) requiring the Board to rescind the order and hold a new hearing of the application, in the manner specified in the directive; and

(b) providing that clauses (1) (a) and (b) apply with respect to the new hearing.

**Limitation**

(5) Subsection (4) applies with respect to orders made on or after February 22, 2024 and before January 1, 2025.

**Procedural fairness does not apply**

(6) Neither the issuance or approval of a directive under this section nor any action taken by the Board to implement or comply with it is subject to any duty of procedural fairness, including any requirement to provide notice, reasons or an opportunity to make submissions.

**Same**

(7) Subsection (6) applies despite the *Statutory Powers Procedure Act* and any other law.

**Conflict**

(8) In the event of a conflict between a directive under this section and the *Statutory Powers Procedure Act*, the rules made by the Board under section 25.1 of that Act or an order of the Board or other instrument or document made or issued under this Act, the directive prevails to the extent of the conflict.

**Publication**

(9) A directive issued under this section shall be published in *The Ontario Gazette*.

**Not a regulation**

(10) For greater certainty, Part III (Regulations) of the *Legislation Act, 2006* does not apply to directives issued under this section.

**(2) Subsections 96.2 (4) and (5), as enacted by subsection (1), are repealed.**

**9 Clause 98 (2) (b) of the Act is amended by striking out "the requirements of section 90" and substituting "the requirements of subsection 90 (1)".**

**10 (1) Subsection 127 (1) of the Act is amended by adding the following clauses:**

(j.12) governing processes under section 4.4, including,

(i) prescribing other persons for the purposes of subsection 4.4 (1) or (2), and

(ii) requiring that specified persons be included in a process for the purposes of subsection 4.4 (3);

(j.12.1) governing processes under section 4.4.1, including,

(i) prescribing other persons for the purposes of subsection 4.4.1 (1), and

(ii) requiring that specified persons be included in a process for the purposes of subsection 4.4.1 (2);

**(2) Subsection 127 (1) of the Act is amended by adding the following clauses:**

(j.16.1) governing exemptions ordered by the Board under subsection 95 (2);

(j.16.2) establishing and governing procedural requirements that apply to determinations of the Board under subsection 95 (2);

**Commencement**

**11 (1) Except as otherwise provided by this section, this Act comes into force on the day it receives Royal Assent.**

**(2) Subsection 5 (2) comes into force on January 1, 2029 or an earlier day to be named by proclamation of the Lieutenant Governor.**

**(3) Subsection 5 (1), sections 6 and 7, subsection 8 (2), section 9 and subsection 10 (2) come into force on a day to be named by proclamation of the Lieutenant Governor.**

**Short title**

**12 The short title of this Act is the *Keeping Energy Costs Down Act, 2024*.**

**Ontario Energy Board** **Commission de l'énergie de l'Ontario**

Ontario

**EB-2007-0615**
**EB-2007-0606**

**IN THE MATTER OF** the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

**AND IN THE MATTER OF** an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2008.;

**AND IN THE MATTER OF** an Application by Union Gas Limited for an Order or Orders approving or fixing a multi-year incentive rate mechanism to determine rates for the regulated distribution, transmission and storage of natural gas, effective January 1, 2008;

**AND IN THE MATTER OF** a combined proceeding Board pursuant to section 21(1) of the *Ontario Energy Board Act 1998*.

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Paul Sommerville
Member

Cynthia Chaplin
Member

**DECISION**

**March 11, 2008**

## Background

Enbridge Gas Distribution Inc. ("Enbridge") filed an Application on May 11, 2007 under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Sched. B, as amended, for an order of the Ontario Energy Board approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2008.

Union Gas Limited ("Union") filed an Application on May 11, 2007 under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Sched. B, as amended, for an order of the Ontario Energy Board approving or fixing a multi-year incentive rate mechanism to determine rates for the regulated distribution, transmission and storage of natural gas, effective January 1, 2008.

Union and Enbridge each filed Settlement agreements which addressed most of the components of an incentive regulation ("IR") plan (dated January 14, 2008 and February 4, 2008, respectively). The Board, by decision dated January 17, 2008, accepted the Union settlement agreement, and by decision dated February 11, 2008, accepted the Enbridge settlement agreement. In both cases, however, the issue of how customer additions should be treated was unsettled.

Green Energy Coalition ("GEC") and Pollution Probe took the position that IR reduces the incentives for Union and Enbridge to invest in new customer additions compared to cost-of-service regulation. This reduced incentive arises because even though customer additions are profitable in the long-term, customer additions often result in short-term revenue deficiencies. These revenue deficiencies arise when the revenues a customer contributes in the early years after the connection are lower than the costs of having added that customer to the distribution system. As a result, GEC and Pollution Probe were of the view that customer additions should be treated as a Y factor in the IR plan. This proposal would have the affect of raising rates to all customers, although by a relatively small amount.

## The Proceeding

On February 1, 2008, the Board heard oral testimony on the matter, including Union's and Enbridge's Argument-in-Chief opposing any adjustment to the IR plan for customer additions. The Board received a joint submission from the Building Owners and Managers Association of the Greater Toronto Area ("BOMA"), the London Property Management Association ("LPMA"), and the Wholesale Gas Service Purchasers Group ("WGSPG"). The Board also received submissions from Energy Probe and the

Industrial Gas Users Association ("IGUA"). Each of these parties supported the position of Union and Enbridge.

On February 6, 2008 GEC and Pollution Probe filed written argument. Union and Enbridge filed reply argument on February 8, 2008.

**The Proposals**

Pollution Probe proposed that the annual revenue deficiencies associated with new customer additions for Enbridge and Union should be treated as a Y factor. In other words, the annual revenue deficiency associated with customer attachments would be treated as a cost pass-through.

GEC proposed an annual incentive/penalty scheme based on a target number of customer additions as a percentage of Ontario housing starts as follows:

**GEC Proposal for Treatment of Customer Additions**

| Natural Gas Utility | Incentive/Penalty | Target or Pivot |
|---|---|---|
| Enbridge | $141 per customer addition | 66.2% of Ontario housing starts (or alternatively, 102.6% of housing starts in Enbridge's franchise area) |
| Union | $141 per customer addition | 35.4% of Ontario housing starts |

The targets or pivot points were based on the five year average of the relationship between customer additions for Union and Enbridge and Ontario housing starts for the years 2002-2006. GEC also proposed that the incentive/penalty could be paid or recovered in the following year or at rebasing for simplicity.

**Board Findings**

The Board finds that the evidence does not support the conclusion that the new IR framework for Union and Enbridge will create a customer addition disincentive which requires an incremental rate adjustment.

Enbridge and Union testified that their IR plans are sufficient to support their capital investment programs. In particular, witnesses for each company stated that when they have to make capital budget reductions, revenue-generating capital investments such as customer additions is the last category to be cut. In the companies' view, there are several reasons for this:

1. Attaching customers provides the companies with a long-term revenue stream. Both companies noted that reducing customer additions would reduce the first-year revenue deficiency impact, however, they would also be giving up future revenue stream that would contribute to their earnings.

2. The core business of the companies is to provide natural gas services to customers; the companies have an obligation to serve and the business is expanded by new customer additions.

3. If the companies fail to attach new customers then these customers will use some other energy source and will be lost until that customer replaces its equipment, which could be fifteen years or more.

The Board acknowledges that there are short-term revenue deficiencies from customer additions in the early years after connection, because the costs of adding these customers are greater than the revenues generated by these customers. However, there are also revenue sufficiencies generated by customers that were connected in previous years because the costs associated with customers added in the past are more than offset by the revenues they generate. As Union and Enbridge argued customer additions from previous years could more than offset the revenue deficiencies in any given year.

GEC and Pollution Probe both advanced arguments that the disincentive could be observed in past results for Union.

GEC argued that a drop in Union's customer additions in 2001 was linked to the ratemaking framework in that year. However, Union in its reply argument stated two possible reasons for this change: 1) the manufacturing sector in southwestern Ontario experienced a sharp decline and 2) a steep increase in its commodity charges. Also, Union stated that it had experienced a fairly constant level of customer additions from 2000 to 2006 with only three cost-of-service applications in 1999, 2004 and 2007. The

Board concludes that there is no evidence to conclude that the level of customer additions in 2001 was lower than it would otherwise have been as a result of Union's ratemaking framework at the time.

Pollution Probe claimed that the change in Union's rolling profitability index between 2002 and 2003 (from 1.29 to 1.49) was the result of Union rationing its capital. Union in its reply argument stated that the year 2003 (along with 2004) represented the high water mark of annual customer additions in the seven year period from 2000 to 2006. The Board concludes that there is no evidence to support the conclusion that Union rationed its capital available for customer additions during the years in question.

The Board concludes that the underlying and long term incentives to make customer additions (a company's incentive to seek long-term revenue and business growth, the risk of lost opportunities if a customer is not added when equipment choices are being made, and the company's obligation to serve customers) are greater than the potential disincentive to make customer additions under an IR framework.

In addition, the evidence regarding Union and Enbridge's specific plans does not support the conclusion that there is a substantive disincentive in any event. For Union, the evidence shows a modest revenue sufficiency over the five year IR plan term (Exhibit C20.5 Updated). Enbridge's IR plan specifically recognizes the number of customers because the forecast of customer additions will be part of each year's revenue per customer cap determination.

The Board concludes that no IR plan adjustment mechanism related to customer additions is required. The result is that the approved IR plans will not be adjusted and there will be no additional impact on customers arising from the resolution of this issue.

**Cost Claims**

The Board in its Decision on Motion dated October 15, 2007 allowed that for the purposes of the EB-2007-0606/0615 proceeding eligible intervenors could claim costs on a phased basis. Phase 1 comprised costs incurred to October 19, 2007, being the filing date for intervenor evidence. In this regard the Board issued a Decision and Order on February 7, 2008.

The Decision on Motion indicated that that phase 2 would pertain to costs incurred between the filing date for intervenor evidence and the end of the oral hearing and that phase 3 would pertain to costs incurred between the end of the oral hearing and the completion of argument.

With the issuance of this Decision, phases 2 and 3 are completed for all issues, except for the unsettled issues of Risk Management and the Treatment of Taxes.

Eligible intervenors will be afforded the opportunity to file their claims for costs incurred to February 8, 2008, including costs related to the unsettled issues. Eligible intervenors also have the option to file a single claim after the completion of argument for the unsettled issues at which time the Board will set the filing particulars.

Accordingly, eligible intervenors claiming costs incurred to February 8, 2008 are to file their claims by April 2, 2008 in accordance with the Board's Practice Direction on Cost Awards. Enbridge and Union shall have until 14 calendar days from the date the cost claim was filed to object to any aspect of the costs claimed. The party claiming costs shall have 7 calendar days from the date of filing of the objections to file a reply. Filings are to be in the form of two hardcopies and one electronic copy in searchable PDF format at boardsec@oeb.gov.on.ca and copy Union Gas Limited and Enbridge Gas Distribution Inc.

**DATED** at Toronto, March 11, 2008.

*Original signed by*

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Gordon Kaiser
Presiding Member and Vice Chair

*Original signed by*

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Paul Sommerville
Member

*Original signed by*

____________________________

Cynthia Chaplin
Member

**EB-2006-0606**
**EB-2007-0615**

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c.15 (Sched. B);

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving a multi-year incentive rate mechanism to determine rates for the regulated distribution, transmission and storage of natural gas, effective January 1, 2008;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2008;

AND IN THE MATTER OF a combined proceeding Board pursuant to section 21(1) of the Ontario Energy Board Act, 1998.

# ARGUMENT OF THE GREEN ENERGY COALITION

## Issue 5.1 – Y factored incentive for customer additions

### 1. GEC's Incentive Proposal:

GEC proposes a targeted symmetrical incentive for total customer additions.

For Union Gas the incentive would be $141 per addition above or below 35.4% of Ontario housing starts in the year. The incentive could be paid or recouped in the following year (or at rebasing for simplicity). For Enbridge the incentive would be $141 per addition above or below 66.2% of Ontario housing starts (or alternatively, 102.6% of housing starts in Enbridge's franchise area). These ratios are the five year averages of the actual experience for each company for the years 2002-2006 as reported by the companies (as set out in exhibits K2.2 and K2.3). The incentive would be symmetrical, returning a similar amount to ratepayers for underperformance. The additions would be calculated on the same basis as the companies did in exhibits K2.2 and K2.3[1].

**Rationale for the Incentive:**

The rationale for GEC's proposal is that multi-year IR regulation reduces the incentives that the companies had under annual cost of service regulation to invest capital. In the case of customer additions or attachments this threatens to reduce benefits to all ratepayers and to society as a whole. Undoubtedly, the pushes and pulls the companies will face on this are complex. GEC is concerned that the short term revenue reduction due to the delayed recognition of these capital additions in rate base changes the equilibrium and, depending on the circumstances faced by the company at any given time, this could result in some less cost-effective attachment opportunities being dropped. GEC's starting point is that the level of incentive that the companies had under COS to add customers was implicitly judged adequate by the Board, and our proposal simply seeks to maintain that level. It is designed to be revenue neutral if the relatively stable trend of attachments relative to housing starts prevails, and it only takes effect if the companies depart from that trajectory. It is a simple and self-calibrating incentive that only comes into play if the companies do in fact stray from the course. It seeks to reinforce behaviour (additions) which all parties agree is in the ratepayers', government's and public's interest.

[1] Union provided *attachment* data (meters hung) whereas Enbridge provided *additions* data (new bills). However, the economic impact was displayed in Union's C20.4 per *addition*.

## 2. The Evidence and Position of the Companies:

### Need for the Incentive

In its prefiled evidence (B/4/1 page 3, para. 11) in discussing Board Staff's evidence Enbridge stated:

> ...assuming a robust rebasing (update rate base, O&M, volumes customer numbers, revenues, etc) and rates are rebalanced under a COS regulation model, this model provides no incentive for Enbridge Gas Distribution and its shareholders to invest any capital in the business other than the minimum amount to maintain total rate base at the approved 2007 levels. This negative incentive is a function of the robust rebasing and the nature of cash-flows and capital investments for a utility like Enbridge Gas Distribution.

Witnesses for both companies did not challenge the notion that multi-year IR reduces the incentive on the companies to invest capital relative to COS. However, both suggested that it would not be in the interest of the companies reduce spending in the case of customer addition investments (and Enbridge's Mr. Ladanyi went further, suggesting that its model provides a positive incentive for customer additions).

Union's witness, Mr. Birmingham, acknowledged that cutting back on attachments, especially relatively less attractive attachments, would improve short-term earnings (V.2, p. 54, l. 1).

Enbridge's witness, Mr. Hoey was asked by Mr. Klippenstein at v. 2, p. 85:

> MR. KLIPPENSTEIN: ...You've used the orchard analogy. Taking into consideration everything you said, it is still true, in principle, is it not, that Enbridge could reduce its first-year system expansion revenue deficiency by reducing the number of new customer additions which have relatively low PIs? That's true by -- standing by itself; isn't that fair?

MR. HOEY: In theory, you are correct, that that's what you would do. From a practical management point of view, that's not what you would do.

(As noted above, Mr. Ladanyi did not agree, a matter we will return to.)

At page 45 of volume 2 the situation is summarized:

MR. POCH: And so you're not going to -- while the rate escalation formula may protect the company's overall position, in terms of the marginal difference that it makes whether you add a customer or not, you're not getting an increase in return on equity for that added equity investment, not until you rebase.

MR. BIRMINGHAM: That's correct, Mr. Poch. I think if you look at the response to Exhibit C20.4, you'll see exactly that. So when we look at the 2006 customer additions as an example, the first year revenue deficiency would be $3.7 million.

Mr. Birmingham agreed that the IR mechanism results in a delayed and depreciated value of capital being added to rate base at rebasing relative to the situation under COS. (v.2, p. 46, l.10)

Union’s numerical analysis of the impact based on the 2006 portfolio, rates and operating costs in C.20.4 shows that in an IR context where there is no immediate addition to rate base the company would face a $3.7 million reduction in revenues in the year, which amounts to a loss in the year of $141 for each attachment. The second table in that response shows that the company would not recoup that loss from added net revenues in the first five years and that each subsequent year would incur a further $3.7 million loss partially offset by net revenues in subsequent years coming to a cumulative $10.9 million loss by the end of the period.

Union also provided a forecast scenario based on forecast 2008 inputs (C20.5) but this forecast should be taken with a grain of salt. The cumulative effect shown in the second table in C20.5 is a net sufficiency of $3.9 million (rather than the $10.9 million loss in C20.4 based on 2006 assumptions) – a matter that BOMA *et al* make much of in their argument. However, the 2008 forecast scenario assumes operating costs of $2.7 million in 2008 and $3.5 million in each subsequent year, whereas the 2006 scenario used operating costs of $3.1 million in the first year and $3.9 million in subsequent years. At v.2 page 51 this is discussed:

> MR. POCH: And you have included in here some projections. For example, you've shown your operating expenses coming down. That's just your expectation; is that fair? That's not hard-wired in?
>
> MR. BIRMINGHAM: That's correct.

If the higher margin and lower cost of equity that Union forecasts in its C20.5 are used with the same operating costs that were used in the 2006 analysis, the value would be reduced by $2 million for the 2008 portfolio, $1.6 million for the 2009 portfolio and so on, leading to a net cumulative *deficiency* of 2.1 million dollars.

Mr. Birmingham agreed that the numbers in 20.4 are as if IRR covered the 2006 –2010 period and are an apples to apples comparison. (v.2, p. 47,l.6) He also agreed that the cumulative difference amounts to close to 11 million dollars (v.2,p.48. l.26)

Enbridge did not respond to GEC's request in supplementary interrogatory 6 for such an analysis but Mr. Hoey agreed that the Union first year deficiency value of $141 per attachment would be a reasonable approximation of the value that Enbridge would experience. (V. 2, p. 105, l. 17)

As noted above, Mr Ladanyi suggested that the revenue cap per customer formula would somehow give the company a positive incentive to add customers. He repeatedly pointed to Appendix C of the settlement proposal to suggest that each customer would increase EGDI's revenue by $418. That figure is a gross revenue value based on the prior year's average gross revenue per customer. Accordingly, the added revenue figure does not account for the higher than average marginal capital servicing costs to add a new customer. If the capital costs of a new addition were the same as the average embedded, depreciated capital cost per customer, EGDI's formula would provide some protection as Mr. Ladanyi asserts. However, new additions are at a much higher undepreciated cost, a cost that is not met by the formula which preserves gross (not net) revenue per customer, and does so based on average embedded costs.

For both companies, costs, particularly capital carrying costs, arise with each addition. The formulae, while ensuring that the companies receive a fair return overall if they continue as in the past, do not give the companies the same benefit of increased return that was experienced under COS for *each marginal decision* to add a new customer.

The most obvious concern is that in a warm year or otherwise difficult financial period the companies may forego long-term gain (particularly for relatively low P.I. additions) to improve short-term financial performance.

Witnesses for both companies acknowledge that they have performance pay regimes that reward senior executives for annual financial performance. This means that the IRR approach both reduces company profits for additions and brings into play a new motivation for action – executive performance incentives that will now encourage restriction of additions in tough times. This had not been a factor under COS due to the immediate rebasing.

Nevertheless both companies assert that there is no problem, that our concern is "theoretical only".

Union suggests that this is evidenced by the lack of customer addition cutbacks during the 2001-2003 IRM period. However exhibit K2.2 illustrates that total attachments did in fact lag in 2001:

| **<u>Year</u>** | **Ontario** | **Total Attached** | **% of Ont. Starts** |
|---|---|---|---|
| 2000 | 71,521 | 24,437 | 34 |
| **2001** | 73,282 | **21,367** | **29** |
| 2002 | 83,597 | 29,785 | 35 |
| 2003 | 85,180 | 30,066 | 35 |
| 2004 | 85,114 | 31,415 | 36 |
| 2005 | 78,795 | 28,707 | 36 |
| 2006 | 73,400 | 26,346 | 35 |

Mr. Birmingham acknowledged the 2001 lag at v. 2, page 61, line 9 and it is notable that he did not volunteer any explanation.

Further, when expressed as a percentage of Ontario housing starts the slowdown in 2001 remains, suggesting it was not simply due to exogenous factors such as housing starts or general economic slowdown. (Mr. Birmingham did acknowledge that housing starts and mortgage rates are the two largest factors at play, with mortgage rates being a factor in housing starts (v.2, p57, l. 15-20).)

In our submission the slowdown Union experienced in 2001 at the start of the IRM period is consistent with the nature of the problem we seek to address. Union's evidence that attachments did not lag in 2002 and 2003 despite economic pressures on the company is not surprising for Union would have been anxious to maintain attachment levels in the year or two prior to the end of its IRM period as it would have been anxious to avoid the Board reducing its capital budget going forward at rebasing.

Thus the *only empirical evidence* is consistent with the GEC's position that the concern is not merely theoretical.

Both companies say that if they face a squeeze they will "find other efficiencies" before cutting attachments (see Enbridge argument at v.2, page 120, line 1). However, many of the expenditures these companies make are not avoidable. Gas must be compressed. Meters must be read. Calls must be answered in conformity with SQR standards. Safety must not be compromised. Staff, and certainly staff costs, cannot be downsized immediately. But optional capital spending such as customer attachments, particularly attachments with relatively lower P.I.s, can be sacrificed if needed. And reducing investment in marginally performing attachments would be a sacrifice that may not be too dear to make in the interest of holding up quarterly earnings – particularly now that executive bonuses are on the table. Further, one might reasonably ask why the companies would not already be harvesting these "other efficiencies" to the extent available under an IR regime?

The choice of housing starts as the external variable that sets the target level of additions was not challenged by either company's witnesses. At V.2, p. 101, line 10 Mr. Hoey agreed that the correlation had been steady for Enbridge. At v. 2, page 57, in the context of discussing the relationship of housing starts to Union's additions given Union's higher commercial and industrial load, Mr. Birmingham was asked:

> And for small commercial and industrial -- or for any commercial and industrial, housing starts would not be a direct measure, but would you agree it might tell us something about the opportunity to add customers to the extent that both housing starts and commercial and industrial growth are reflections of the growing economy and population, at a macro level?
>
> MR. BIRMINGHAM: At a very high level.
>
> MR. POCH: Sure.
>
> MR. BIRMINGHAM: I think that's probably true.

It is notable that after assuring the Board that the proposals of Pollution Probe and the GEC are unneeded, Mr. Penny went on to suggest that the proposals will reduce rate predictability and stability. If attachment behaviour is as stable and protected as the companies suggest, one wonders how GEC's proposal could lead to instability in rates.

**Administrative Burden?**

Both companies suggest that the costs and difficulties of administering our proposal are unwarranted. This is surely disingenuous. Our proposal is the height of simplicity. Take publicly reported housing starts and multiply by the fixed percentage then multiply any difference by $141. It is a virtually automatic incentive mechanism.

**Double Recovery?**

Ms. Newland raised a concern about double recovery. We are in agreement that a mechanism that rewards additions at levels below the current rate of addition (which we submit is implicitly assumed in the price and rate escalation formulae) would create double recovery. This is precisely the reason GEC proposes a target or pivot at the expected level (adjusted by changes in housing starts to protect the companies from matters outside their control). The companies are presumed to be adequately compensated by the settlements if they continue to add customers at the levels that they have in the past. (Indeed the parties to the Enbridge agreement explicitly reference their reliance on EGDI's forecasts that appear in the appendix to the agreement which includes customer attachments.) Thus it is appropriate that the companies are not rewarded for merely achieving the current levels of attachment. In the same vein, it is appropriate that the companies return monies to customers if they do not reach that level. All customers will be hurt if cost-effective attachments are foregone and the companies should not be unfairly enriched.

### Inadequate Notice of the Proposal?

Ms. Newland complains that the companies haven't had an opportunity to wrestle with our proposal during the prolonged ADR phase. GEC's concern with the impact on customer additions has been known to the parties from the outset. GEC's requests for the information relating additions to housing starts were made during the ADR. GEC has repeatedly stated on the record that it seeks a targeted incentive. GEC did not have the values for deficiency to inject into a formula in Union's case until last week and in Enbridge's case, until Mr. Hoey accepted the Union value on the stand (Enbridge having declined to calculate the values in I.R. I/6/6). The nature and value of the required incentive could not be determined until the context was known. The proposal is simple to understand. This is an objection of form, not substance.

### SQR in Disguise?

Mr. Penny stressed that the Board should view our proposal as a belated attempt to obtain service quality regulation. As a formal matter we do not seek an SQI. We seek a targeted incentive as part of the incentives created in the IRR. However, it is acknowledged that the relatively small amounts we propose may have less an effect as a direct incentive then as a caution to the companies and an indication of expected performance and in that respect the proposal resembles an SQI. The proposal arises in response to the particular settlement proposals developed by the companies and ratepayers. As the Board will see from a comparison of Enbridge's pre-filed evidence with its proposal today, Enbridge was intending to have a greater proportion of its activities within Y factor treatment (see B/4/1/page 12 at para. 33). Enbridge's evidence proposed to address the changed incentive for capital spending as part of IRR. GEC should not be criticised for suggesting the same. It would not have been possible to conclusively determine an appropriate incentive/penalty level prior to the formulae being crystallized in the settlement proposals

Even if it our proposal is seen as SQR, we are unaware of any prejudice that raising it in this process would cause the companies. In our submission the Board should be guided by the substance of what is in the public interest, not some exaggerated reliance on procedural form and timing.

We have noted our view that the potential for a penalty is the most important feature of the proposal. In our experience, utilities are particularly concerned about penalties. A simple SQR would not have had this feature.

### Avoidance of Variance and Deferral Accounts

Mr. Penny argues that the GEC proposal is incompatible with the Board's desire to avoid deferral and variance accounts as expressed in the NGF report. The rationale behind the Board's concern about variance and deferral accounts is surely that these accounts blunt economic signals to the regulated entity. At page 31 of its Report the Board's conclusion was:

> ***In the Board's view, an appropriate balance of risk and reward in an IR framework will result in reduced reliance on deferral or variance accounts, and reliance on off-ramps or z-factors in limited, well-defined and well-justified cases only.***

In other words, these accounts are to be avoided because they can reduce incentives for efficiency and the management of risk. GEC's proposal is the opposite. It adds an incentive for efficient activity. Activity that would reduce rates, help alleviate the difficulties faced on the electric side, and serve government policy. These matters were well canvassed and documented in Mr. Klippenstein's cross of both company panels. The consistency of customer additions with government policy and with Board objectives, particularly those from fuel switching, is not in doubt.

## 3. Position of other Intervenors

Mr. Penny notes that ratepayers reject the need for a Y factor. We observe that ratepayer groups are often focused on near term cost reduction. In our submission, these parties place a higher value on a bird in hand rather than two in the bush. GEC places greater emphasis on long term net benefits to ratepayers and society. Accordingly, the fact that the ratepayers do not support the proposal should not be equated with its appropriateness from a broad public interest perspective. Indeed the Board has rejected aspects of agreements in the past for that reason.

In their argument BOMA *et al* focus on Union's exhibit C20.5 to suggest that the deficiency is *de minimus.* As discussed above, C20.5 is an optimistic projection that assumes lower operating costs then have been experienced and if we adjust for that fact the projected sufficiency becomes a deficiency.

IGUA is concerned about the application of the proposal to industrial customers. The additions covered are those included in the company responses that are reproduced in exhibits K 2.2 and K2.3. In both cases the numbers include non-residential customers other then large industrial (which are routinely addressed by way of customer contribution and would presumably be less susceptible to the concern we raise).

## 4. Conclusion

If our concern is misplaced, as the companies' suggest, there is no harm in what would be a revenue neutral result. It is only if we are right that the incentive would have any impact, and in that case it would be entirely salutary. Either additions would be encouraged that will ultimately lower rates, or unearned profits will be returned to ratepayers for performance below the expectations that underlie the productivity assumptions. GEC acknowledges that the incentive is small and submits that the prospect of a penalty is likely to be the most motivating and important aspect of this formulation. Therefore, GEC respectfully urges the Board to adopt a symmetrical incentive.

## 5. Costs

GEC respectfully requests that 100% of its costs be awarded.

**All of which is respectfully submitted this 6th day of February, 2008**

**David Poch**
**Counsel to the GEC**

KLIPPENSTEINS
BARRISTERS & SOLICITORS
160 JOHN STREET, SUITE 300,
TORONTO, ONTARIO M5V 2E5
TEL: (416) 598-0288
FAX: (416) 598-9520

February 6, 2008

**BY PERSONAL DELIVERY (11 COPIES) AND EMAIL**

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto, Ontario M4P 1E4
Fax: (416) 440-7656
Email: boardsec@oeb.gov.on.ca

Dear Ms. Walli:

**Re: Pollution Probe – Written Argument**
**EB-2007-0606 / EB-2007-0615 – Union Gas / Enbridge – 2008 Rates**

In accordance with the discussion at the hearing on Friday, February 1, 2008, please find enclosed Pollution Probe's written argument for this matter.

Yours truly,

Basil Alexander

BA/ba

Encl.

cc: Applicants and Intervenors per List of Applicants & Intervenors dated August 24, 2007 by email
Board Staff per Procedural Order #1 by email

**EB-2007-0606**
**EB-2007-0615**

# ONTARIO ENERGY BOARD

**IN THE MATTER OF** the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

**AND IN THE MATTER OF** an Application by Union Gas Limited for an Order or Orders approving or fixing a multi-year incentive rate mechanism to determine rates for the regulated distribution, transmission and storage of natural gas, effective January 1, 2008 (the "Union 2008-2012 Rates Application");

**AND IN THE MATTER OF** an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing rates for the regulated distribution, transmission and storage of natural gas, effective January 1, 2008 (the "Enbridge 2008-2012 Rates Application");

**AND IN THE MATTER OF** a combined proceeding before the Board pursuant to section 21(1) of the *Ontario Energy Board Act, 1998.*

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# WRITTEN ARGUMENT on behalf of POLLUTION PROBE

## February 6, 2008

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**KLIPPENSTEINS**
Barristers & Solicitors
160 John St., Suite 300
Toronto ON M5V 2E5

**Murray Klippenstein**
**Basil Alexander**
Tel: (416) 598-0288
Fax: (416) 598-9520

**Counsel for Pollution Probe**

# Table of Contents

# Introduction

Pollution Probe's submissions with respect to the applications by Enbridge and Union Gas for incentive rate mechanisms for 2008-2012 focus on whether revenue deficiencies associated with new customer additions should be treated as a Y factor (Issue 5.1).

As detailed below, Pollution Probe submits that such revenue deficiencies should be treated as a Y factor to retain an incentive in favour of new customer additions, given the benefits of system expansion, the Board's statutory mandate to facilitate rational system expansion, the Government of Ontario's conservation policy, the Board's guidelines for natural gas incentive rate regulation, and the current existing status-quo regulatory treatment of such system expansion. The partial settlements should therefore be modified accordingly on this one point.

In the specific case of Enbridge, its proposal may have built in a specific commitment to provide a minimum yearly amount of system expansion during the term of its settlement agreement, in which case Pollution Probe submits that the revenue deficiencies associated with system expansion above these set minimums should be treated as a Y factor.

# Detailed Submissions

***The Benefits of Adding More Customers to Ontario's Natural Gas System***

Pollution Probe submits that attaching new customers to the Enbridge and Union natural gas distribution network provides the following benefits to Ontario and the gas utilities:

1. New attachments lower the overall energy bills of the new customers;
2. In the long run, new attachments lead to lower natural gas distribution rates for all of the utilities' customers;
3. By reducing the overall demand for electricity for space heating, water heating, cooking and drying, new attachments reduce the need for new high-cost electricity infrastructure;
4. By reducing the overall demand for electricity and oil for space heating and other needs through increased natural gas use, new attachments reduce Ontario's total greenhouse gas emissions; and
5. By increasing the utilities' rate base, new attachments permit the utilities to increase their earnings per share.

Pollution Probe submits that the above benefits underlie and are implemented through various measures as detailed below.

*The Board's Legislative Mandate to Expand Ontario's Natural Gas System*

As a result of the above-noted benefits of adding new customers to Ontario's natural gas distribution system, the Ontario Energy Board has a statutory mandate to facilitate the rational expansion of Ontario's natural gas distribution system. Specifically, according to section 2 of the *Ontario Energy Board Act*:[1]

> The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:
>
> ...
>
> 3. To facilitate the rational expansion of transmission and distribution systems.
>
> ...

*The Government's Conservation Policy to Expand Ontario's Natural Gas System*

In addition, as a result of the above-noted benefits, it is Government of Ontario policy that end-use fuel switching from electricity to natural gas should be promoted to help achieve its energy conservation goals with respect to electricity.[2]

This is significant because, as the Board is aware, the *Ontario Energy Board Act* requires the Board, when regulating Ontario's gas utilities, to promote energy conservation in a manner consistent with Government policy:[3]

> The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:
>
> ...
>
> 5. To promote energy conservation and energy efficiency in a manner consistent with the policies of the Government of Ontario.
>
> ...

*The Board's IR Guidelines – Creating An Environment Conducive to Investment*

In March 30, 2005 the Ontario Energy Board issued its guidelines for natural gas incentive regulation, i.e., for this proceeding. According to the Board's *Report*, the gas utilities' new multi-year incentive regulatory framework must "create an environment that is conducive to investment, to the benefit of both customers and shareholders."[4]

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[1] Exhibit K2.1, Tab 1 (*Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule A, s. 2).
[2] Exhibit K2.1, Tab 4.
[3] Exhibit K2.1, Tab 1 (*Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule A, s. 2).
[4] Exhibit K2.1, Tab 2 (*Natural Gas Regulation in Ontario: A Renewed Policy Framework – Report on the Ontario Energy Board Natural Gas Forum* dated March 30, 2005, pg. 18)

*The Existing Board-Approved Regulatory Framework for Gas Utilities*

Under the Board's existing cost of service regulatory framework for Ontario's gas utilities, attaching new customers is in the long-run self-interest of the gas utilities since it leads to more rate base and hence the potential for the utilities to increase their earnings per share.

However, on a stand alone basis, new customer additions are not economic during their early years. That is, their stand alone revenues are less than their stand alone costs.

For example, according to Union Gas, on a stand alone basis, its year 2006 revenues from its year 2006 new customer additions were $3.7 million less than their costs. Furthermore, according to Union, if one assumes that every year of the 5 year term of incentive regulation has the same revenue sufficiency/(deficiency) impact as the 2006 customer additions, the resulting cumulative revenue deficiency would be $10.9 million.[5]

According to Enbridge, on a stand alone basis, the cumulative 5 year revenue deficiency of its year 2006 new customer additions was $4.458 million.[6]

As a result, on a stand alone basis, new customer additions are not in the utilities' short run self-interest since they will reduce their earnings per share. To eliminate this conflict between the utilities'short run and long run self interest, the Board has permitted the utilities to submit annual rate applications to recover, via higher rates spread over all of their customers, their stand alone revenue deficiencies from their new customer additions.

In short, since the creation of TransCanada pipeline system in the late 1950s, attaching new customers has been in the short run and long-run financial self-interest of Enbridge and Union with only one brief exception, namely, Union's trial PBR term between 2001 and 2003. This is probably one reason why Ontario's gas utilities have experienced a very dramatic customer attachment growth during the past half century.

*The Issues with the Partial Settlement Proposals re: System Expansion*

The Board is now being asked by Enbridge and Union and selected intervenors to establish a new regulatory regime which would deny Enbridge and Union their right to apply to the Board, on an annual basis, to recover their revenue deficiencies associated with new customer additions.

According to Enbridge and Union their proposal is in the public interest since: a) it will lead to lower natural gas distribution rates in the short term; and b) there is no evidence that denying the gas utilities the right to recover their new customer addition deficiencies will reduce their number of new customer additions.

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[5] Exhibit K2.1, Tab 6, pgs. 13-14 (Union Exhibit C20.4 – Updated) and Transcript, Volume 2 (February 1, 2008), pg. 33.
[6] Exhibit K2.1, Tab 7, pg. 20 (Enbridge Exhibit I, Tab 9, Schedule 5, Attachment).

Specifically, according to Vice President Birmingham of Union Gas, allowing Union to continue to raise its rates to recover its new customer additions is contrary to the public interest because it is not needed:[7]

> What you would be talking about is annual rate increases to reflect any revenue deficiencies for the new customer additions. That will result in rate increases with no discernable benefit to ratepayers. And ***it's not going to change Union's behaviour at all.*** [emphasis added]

Furthermore, according to Union's counsel, Mr. Penny:[8]

> So the fundamental premise of the entire argument of my friends, in my submission, is that Union will cut customer additions for short-term gains during the incentive regulation plan, and there's simply no support for that premise. ***There's no historical support.*** There's no support in the forecast evidence, and ***the company clearly has no financial incentive to do that.*** As you heard repeatedly, the last thing you would do is reduce revenue-producing capital. [emphasis added]

Pollution Probe respectfully disagrees with Mr. Birmingham and Mr. Penny.

Pollution Probe agrees that new customer additions are in the long-run self interest of Enbridge and Union. Therefore Pollution Probe is not suggesting that if the partial settlement agreement is approved, that they will stop making new customer additions. Rather, Pollution Probe submits that, if the settlement agreement is approved, they will make fewer new customer additions relative to what they would implement if the existing regulatory framework is maintained (on this point).

Pollution Probe's reasons for these submissions are as follows.

First, while Enbridge and Union want to grow their businesses by adding new customers, they also want to ensure that in each and every year they earn, at least, their Board-approved return on equity. In a year with a mild winter or an economic recession or both, Enbridge and Union will have to dramatically reduce their spending to ensure that they continue to earn their Board-approved return. As a result, they may be required to sacrifice their long-term self-interest by cutting back on their new customer additions.

Second, Enbridge Gas Distribution and Union Gas are owned by Enbridge Inc. and Spectra Energy respectively – both of which are traded on the New York Stock Exchange. As the Board is aware, both of these companies are under intense pressure from the investment community to achieve ever increasing earnings per share. As a result of this pressure, under the respective partial settlement agreements, Enbridge and Union would be able to increase their short-term earnings by cutting back on their new

[7] Transcript, Volume 2 (February 1, 2008), pg. 34.
[8] Transcript Volume 2 (February 1, 2008), pg. 117.

customer additions ***even in good years***. Accordingly, the utilities' respective parent companies might require or pressure them, explicitly or implicitly, to cut back their new customer additions in order to help Enbridge Inc. or Spectra Energy increase their next quarter's earnings (i.e. the short-term interest would trump the long-term interest).

Third, according to Mr. Penny, there is no historical support for Pollution Probe's proposition that the utilities will cut back their customer additions to increase short run profits if they cannot recover their new customer revenue deficiencies by raising their rates. In fact, there appears to be evidence to support precisely that.

During the last fifty years or so, the gas utilities have always been able to recover their new customer addition revenue deficiencies via annual rate increases with only one brief exception, i.e., Union Gas was not able to do so during the term (2001 to 2003) of its trial PBR (performance-based regulation). Therefore, if there is to be Ontario-specific historical support for Pollution Probe's proposition, it will have to be with respect to actions by Union Gas during the 2001 to 2003 time period.

According to Mr. Birmingham, in 2003 Union's parent was in dire financial straits and was looking for ways to cut back its capital budget:[9]

> In 2003, which was the final year of our trial performance-based regulation framework, in that year we had a 2.3 percent rate reduction. So, not the rate increase that we're looking for 2008 and the rate increases that we would be expecting through the incentive regulation period, but a 2.3 percent rate decrease.
>
> ***We had a shareholder who was in dire financial straits and so we were in the situation where we were looking to constrain as much capital as we could.*** [emphasis added]

According to Pollution Probe's submissions, in such a situation Union would feel pressure, explicitly or implicitly, to reduce its least profitable new customer additions in order to ration its capital and minimize its short-run rate deficiency. Furthermore, as Mr. Birmingham conceded under cross-examination, reducing its least profitable new customer additions (i.e., customer additions with a low P.I. or profitability index) entails that the overall P.I. of its portfolio of new customer additions would rise:[10]

> MR. KLIPPENSTEIN: Could Union reduce its first-year system expansion revenue deficiency by reducing its number of new customer additions which have relatively low PIs?
>
> MR. BIRMINGHAM: Well, to the extent that those customer additions are contributing to the first-year revenue deficiency, reducing those customer additions would reduce the first-year impact. The problem with that approach is

[9] Transcript, Volume 2 (February 1, 2008), pg. 12.
[10] Transcript, Volume 2 (February 1, 2008), pg. 28 line 13 to pg. 29, line 3

> that you give up all of the future years' revenue that then contributes to the earnings of the company.
>
> MR. KLIPPENSTEIN: Given what you said, it would also be true, I take it, that ***Union would reduce its first-year system expansion revenue deficiency by reducing its number of low PI customer additions and thereby increasing the aggregate PI of its portfolio of new customer additions?***
>
> MR. BIRMINGHAM: I guess to the extent that those are customer additions that are not caught under the obligation to serve, ***that's a theoretical possibility, but it's not a practical approach for us.*** [emphasis added]

In fact, the evidence suggests that in 2003, when its parent company was in dire financial straits, the "theoretical possibility" became "a practical approach" for Union. Specifically, in 2003 the P.I. of Union's portfolio of new customer additions rose to 1.46 from a base of 1.29 in 2002.[11] By reducing, to the fullest extent practical, its low PI new customer additions, Union appears to have rationed its capital and reduced its revenue deficiency, just as Pollution Probe's argument would predict.

***Responding to IGUA's Argument Regarding a Potential Enbridge Windfall***

According to the Industrial Gas Users Association ("IGUA"), if the Board accepts Pollution Probe's recommendations, Enbridge will earn a windfall profit:[12]

> Further, EGD's witness, Mr. Hoey, confirmed that the introduction of Y factor treatment to costs arising from customer additions, as proposed by GEC and Pollution Probe, would result in over-recovery or double-recovery by the company [Transcript, Vol. 2, p. 106]. Thus, ***Y factor treatment of these costs would result in a windfall for the utility.*** [emphasis added]

IGUA's submissions assume that the Enbridge partial settlement agreement is based on a commitment by Enbridge that it ***will*** undertake a certain minimum number of new customer additions during each of the next 5 years. If this is the case, Pollution Probe invites Enbridge in its reply argument to specify the minimum number of new customer additions it will make during each of the next 5 years. If IGUA's submissions about Enbridge's commitment are correct, Pollution Probe's argument above would still fully apply with the modification that, for Enbridge, revenue deficiencies for new customer additions <u>above these minimum amounts</u> should be treated as a Y factor.

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[11] Exhibit K2.1, Tab 7, pg. 17 (Exhibit C20.6).
[12] IGUA Submissions by letter dated February 4, 2008 at the last paragraph of pg. 1.

## Conclusions and Submissions

Pollution Probe submits that the respective partial settlement proposals, insofar as they effectively revoke the Board's long-standing policy of allowing the utilities to apply for annual rate adjustments to recover their revenue deficiencies associated with new customer additions, should ***not*** be approved.

Pollution Probe's reasons for this submission are as follows..

1. Pollution Probe submits that new customer additions that pass the Board's E.B.O. 188 guidelines are in the public interest,[13] and such attachments should thus be encouraged and promoted. The Board should accordingly ***not*** adopt a new ratemaking framework that financially penalizes the gas utilities in the short-term for attaching new customer additions that pass the E.B.O. 188 test. If such a framework were adopted, the Board would be effectively and practically repealing in part the intent of the E.B.O. 188 guidelines without proper notice and consideration.

2. Pollution Probe further submits that it would be contrary to the Board's statutory obligation to facilitate the rational expansion of Ontario's natural gas distribution system to financially penalize the gas utilities for attaching new customer additions that pass the E.B.O. 188 test.

3. Pollution Probe further submits that it would be contrary to the Board's statutory obligation to promote energy conservation in a manner consistent with the conservation policies of the Government of Ontario to financially penalize the gas utilities for attaching new customer additions.

4. Pollution Probe further submits that it would be contrary to one of the Board's key criteria for performance-based regulation in the natural gas sector (i.e. creating an environment that is conducive to investment to the benefit of both customers and shareholders) to financially penalize the gas utilities for attaching new customer additions.

Pollution Probe thus submits that the Board should allow the gas utilities to recover the annual revenue deficiencies associated with their new customer additions as a Y factor.

With respect to Enbridge, Pollution Probe's argument would apply, potentially subject to a modification to adjust for one alleged feature of Enbridge's proposal. Specifically, if Enbridge's reply argument provides:

1. confirmation that its partial settlement agreement is based on the assumption that Enbridge will make a specified number of new customer additions during each of the next 5 years; and

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[13] Exhibit K2.1, Tab 3 (Excerpt from *Final Report of the Board* in E.B.O. 188 dated January 30, 1998).

2. the minimum number of new customer additions that Enbridge will make during each of the next 5 years, then

Pollution Probe submits that the Board should allow Enbridge to recover as a Y factor its annual revenue deficiencies associated with new customer additions that are in excess of these minimum commitments. If Enbridge does not confirm the above two points in its reply, Pollution Probe submits that the Board should make an order allowing Enbridge to recover as a Y factor its annual revenue deficiencies associated with all its new customer additions.

## Costs

Pollution Probe respectfully requests that it be awarded 100% of its reasonably incurred costs of participating in this proceeding. Pollution Probe submits that its participation was responsible and assisted the Board in its consideration of the issues. In addition, Pollution Probe is a registered charity that has no pecuniary interest in the outcome of this proceeding, and its membership includes thousands of gas consumers.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

February 6, 2008

Murray Klippenstein, Counsel for Pollution Probe

Basil Alexander, Counsel for Pollution Probe

**KLIPPENSTEINS**
Barristers & Solicitors
160 John St., Suite 300
Toronto ON M5V 2E5

**Murray Klippenstein**
**Basil Alexander**
Tel: (416) 598-0288
Fax: (416) 598-9520

**Counsel for Pollution Probe**

Exhibit M9-GEC-ED Energy Transition

**Before the Ontario Energy Board**

EB-2022-0200

# Enbridge Gas 2024 Rebasing

Prepared by:

**Chris Neme**

**Energy Futures Group**

Prepared for:

**The Green Energy Coalition**
Greenpeace Canada
Sierra Club Ontario Chapter

**Environmental Defence**

**May 11, 2023 (updated May 30th)**

# Table of Contents

# I. Executive Summary

This report discusses the risk that infrastructure built pursuant to Enbridge's current application may ultimately be underutilized or stranded due to market forces and/or climate policy, and proposes steps that Enbridge and the Ontario Energy Board (OEB or Board) can take to mitigate those risks to consumers. The report is authored by Chris Neme, a Principal with Energy Futures Group (EFG). Mr. Neme and his firm are leading experts on the implications of decarbonization for gas customers and best practices to address those implications. Mr. Neme has decades of experience with Enbridge Gas and the Ontario regulatory context from approximately 30 years of work on gas and (to a lesser extent) electric DSM in the province, and participation in various OEB advisory committees on DSM, Gas IRP, and carbon prices. What follows are the key conclusions and recommendations of the report.

## 1. Key Conclusions

I conclude in this report that major declines in peak and annual gas demand are very likely in the future as efforts to decarbonize the Ontario economy accelerate. This is the conclusion of most independent decarbonization pathways studies. It is also consistent with an analysis of the availability and feasibility of the electric and gas technologies required for net zero greenhouse gas (GHG) emissions and the current cost effectiveness of electrification. It is even consistent with results of Enbridge's own decarbonization study if just one of the most glaring of the many flaws in the study is corrected. I discuss each of these points in some detail in Section III of this report.

The potential implications of declining gas peak demand and gas sales are significant and important. In a nutshell, there is a growing risk that current and any new gas capital assets will become underutilized, if not stranded. This creates significant risks for the ratepayers who would be saddled with paying for those assets in the future. It will likely also create significant inequities between customers today and those left on the system in the future who end up paying for an inappropriate and disproportionately large share of the cost of gas system assets – including assets that were intended primarily or exclusively to meet the needs of other customers who will have left the gas system. This will be particularly problematic for lower-income households who could face the biggest hurdles to exiting the system.

There are a variety of ways in which the Board should mitigate those risks. In particular, I recommend the following:

1. **Shorten new construction connection cost recovery periods**. There are two components to this recommendation:
    a. **Reduce the customer revenue horizon from 40 years to 15 years**. This will reduce the risk that new customers do not end up covering the full cost of their connection to the system through rates, let alone contributing to other system costs, if they electrify at the time that their new heating system needs to be replaced. Enbridge estimates this change would reduce system access spending by about $600 million over the 2024-2028 period.
    b. **Reduce the maximum customer connection horizon from the current 10 years to 5 years**. Given the likelihood that gas sales will begin to decline, it is prudent to put tighter limits on the sunsetting of connection offers to builders and developers.
2. **Reduce infill connection costs funded by rates to the amount that will be recouped from resulting gas bills over 15 years**. Analogous to the above recommendation, this will reduce the

risk that new customers do not end up covering the full cost of their connection to the system through rates, let alone contribute to other system costs.

3. **Require all new connections to be net-zero greenhouse gas emitting**. This would include requiring that all new connections install hybrid heating systems with a cold climate air source heat pump meeting the vast majority of heating needs (and a back-up gas furnace functioning only during the coldest hours of winter). Also, all gas provided to new connections would have to be biomethane (often called renewable natural gas or RNG). This recommendation is similar to a proposal that Energir, the Quebec gas utility, recently proposed for its upcoming rate case.
4. **Require Enbridge to immediately assess and report back to the Board by 2024 on the near-term and longer-term rates, costs of capital, affordability, and inter-generational equity impacts of alternative asset depreciation approaches**. The current approach to depreciation is highly problematic because it does not address decarbonization risks at all and implicitly assumes a 0% risk of underutilized or stranded assets even long past 2050. The Company should assess, among other things, a Units of Production approach, which could account for declining annual sales, and thus promote better inter-generational equity and help to ensure affordability as demand declines. Depreciation approaches that account for decarbonization should be studied now because delaying a shift in approaches will cause increasingly large rate shocks as time goes on.
5. **Require Enbridge to routinely assess trade-offs between repairing and replacing aging pipe.** The assessments should account for the possibility that a new pipe will be underutilized or stranded before the end of its life as a result of decarbonization policies or market forces significantly driving down gas demand in the future. They should include estimates of near-term cost savings and related differences in rate impacts, any potential differences in long-term costs and rate impacts, the magnitude of any differences in methane leaks, the nature of any differences in safety risks, and the long-term potential to save money by cost-effectively pruning the gas system.
6. **Improve IRP to reduce the risk of under-utilized or stranded assets**. There are two components to this recommendation:
    a. **End the interim prohibition on considering electrification measures as IRP Alternatives (IRPAs).** Things have changed since the Board put this prohibition in place in the gas IRP proceeding several years ago. Our understanding of decarbonization includes both recognition of the likelihood that significant electrification will occur and new direction from the Minister. Indeed, the Board recently required Enbridge to provide rebates for electric heat pumps through its DSM programs. It would be prudent to enable Enbridge to target electrification to areas that could simultaneously reduce other gas infrastructure investment costs.
    b. **Require analysis of IRPAs under multiple possible future load forecasts that include the effects of decarbonization of the economy.** To date, Enbridge has based its assessment of system needs and the role that IRPAs could play in cost-effectively deferring such needs on forecasts that do not reflect the likely impacts of decarbonization on demand. At a minimum, assessments of cost-effectiveness should consider demand declines as a material possibility.
7. **Consider the creation of a segregated fund for site restoration.** Enbridge currently retains billions of ratepayer dollars for future site restoration costs. This creates a material risk for

customers, which is increasing as decarbonization unfolds. A third-party study should be commissioned on a segregated fund restoration funds and how to maximize returns on the funds and minimize costs and liability for existing customers. This issue should be revisited in phase II based on that study.

8. **Reduce capital spending on gas assets whenever possible.** The risk of underutilized and stranded assets calls for maximizing scrutiny of opportunities to reduce capital spending that will be added to rate base, wherever that is possible, especially for long-lived infrastructure.

# II. Introduction

On October 31, 2022, Enbridge Gas Inc. (Enbridge) filed its 2024 Rebasing application and evidence. The application requests approval of rates for the sale, distribution, transmission and storage of gas. The Company also requests approval of an incentive rate-making mechanism for 2025 through 2028. The Company's evidence is extensive, covering a wide range of information, including but not limited to its demand forecast, capital spending requirements under its asset management plan, its cost of capital, its revenue requirements, and rate design. For the first time, Enbridge's rebasing filing also includes discussion of the energy transition that will be necessary to decarbonize Ontario's (and Canada's) economy and the implications of that transition on many of the requests the Company is making in this proceeding.

This report discusses the risk that infrastructure built pursuant to Enbridge's current application may ultimately be underutilized or stranded due to market forces and/or climate policy. It also proposes regulatory steps the Ontario Energy Board (OEB or Board) should consider to mitigate those risks to consumers.

The report is authored by Chris Neme, a Principal with Energy Futures Group (EFG). Mr. Neme and his firm have extensive experience and expertise in both the development of policies and the assessment of options for, and implications of, decarbonization of fossil gas use in buildings and industry. That includes developing and conducting decarbonization pathways studies (e.g., in Massachusetts, Vermont and Delaware); helping clients review and provide input to similar studies led by other firms (e.g., the recent Massachusetts gas utilities study); reviewing and critiquing studies on renewable gas potential (e.g., a 2022 Michigan study); assessing the reasonableness of RNG pilot program proposals (Illinois); assessing the need for pipeline expansion in the context of local decarbonization policies (in testimony before the U.S. Federal Energy Regulatory Commission on behalf of the state of Washington); assessing the customer economics of electrification (e.g., in Illinois, Michigan, Nevada and British Columbia); supporting the design of electrification programs (e.g., in Michigan, Illinois and Massachusetts); and supporting the development of over-arching building decarbonization policies (e.g., Vermont's proposed Clean Heat Standard, Michigan's climate plan, and Illinois climate legislation).

Mr. Neme has filed expert witness testimony in 25 different OEB dockets, mostly on gas DSM issues, but also on gas integrated resource planning (in 2020) as well as on Enbridge and Union's carbon cap and trade policies (in 2018). He has also filed testimony on energy efficiency, electrification, integrated resource planning and other distributed energy issues in 45 DSM, IRP, and Rates cases before energy regulators in a dozen different jurisdictions, including the neighboring provinces/states of Quebec, Manitoba, Michigan and Ohio. Mr. Neme was recently appointed to the OEB's DSM Stakeholder Advisory Group, currently serves on the OEB's Gas IRP Working Group, previously served on OEB's Evaluation Advisory Committee and was also previously elected by Ontario stakeholders to serve on the province's Gas Technical Advisory Committee and numerous Enbridge and Union Gas DSM Audit Committees over the past 20+ years. He also previously served as an outside reviewer of Ontario studies on achievable efficiency potential and carbon price forecasts.

# III. Major Declines in Gas Demand from Decarbonization Likely

## 1. Summary

Major declines in peak and annual gas demand are very likely due to decarbonization. I come to this conclusion for the following reasons:

- Most independent decarbonization pathways studies find that high levels of full electrification of buildings will be the least expensive decarbonization pathway.
- Even scenarios with significant hybrid gas-electric heating result in declines in gas demand because RNG feedstocks are expensive and very limited and the amount of hydrogen energy that can be safely blended with methane is very small.
- The Ontario electric grid is already very clean and the technologies required for electrification of buildings (e.g., electric heat pumps) are currently available, well tested, scalable, and have been consistently following a trend of increasing performance.
- The technologies required for high-gas pathways (e.g., gas heat pumps, 100% hydrogen furnaces and other appliances, and 100% hydrogen distribution systems) are largely unavailable today – i.e., they are much more uncertain than electric alternatives.
- RNG prices increase as overall consumption increases (i.e., it has a steep supply curve), which is much less the case with green electricity.
- Full electrification of homes is already highly cost-effective from a consumer price perspective in comparison to fossil methane heating, lowering total energy bills by 37-50% in the very first year and providing nearly $17,000 in 18-year net present value (NPV) savings. Full electrification will likely be even more cost-effective in comparison to decarbonized gas heating (e.g., RNG).
- Considerable GHG emissions persist with most forms of RNG and with blue hydrogen, and there is not yet scientific consensus on the true extent of those emissions, raising the risk that certain "low-carbon" gaseous fuels are actually inconsistent with net zero emissions goals at the volumes required.
- The Guidehouse pathways report that Enbridge is relying upon to support its vision of higher reliance on gaseous fuels is replete with errors and pro-gas biases (see below). Remedying only a few of these would swing the results such that the "electrification" scenario analyzed by Guidehouse is more cost effective, even though that scenario is poorly designed and not a least-cost electrification scenario.

## 2. Technical Options for Decarbonizing Fossil Gas Use in Buildings and Industry

Ontario is currently emitting approximately 150 million tonnes of carbon dioxide equivalents ($CO_2e$) per year.[1] The burning of fossil methane in homes, commercial buildings and industry is responsible for approximately one-third of those emissions. Canada has committed to achieving net zero emissions of $CO_2e$ by 2050 and enshrined that target in legislation.[2] The country's 2030 Emissions Reduction Plan is

[1] Exhibit 1, Tab 10, Schedule 3, Page 2 (based on the latest publicly available data at the time of the application).
[2] Canadian Net-Zero Emissions Accountability Act (https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/net-zero-emissions-2050/canadian-net-zero-emissions-accountability-act.html).

designed to reduce emissions from the buildings sector by 42% relative to 2019 levels.[3] For the fossil methane industry – Enbridge's business – reaching both the short term and longer-term emission reduction goals is going to require dramatic changes. Put simply, it is going to require massive levels of fuel-switching away from fossil methane.

Conceptually, there are essentially three categories of alternatives to fossil methane:

- **Electricity**. The current Ontario electric grid is already more than 90% carbon free[4] and will likely have to get even cleaner for the province to meet its emission reduction goals and the federal government's Clean Electricity Standard, which will require net-zero electricity by 2035.[5] There are a variety of electrification technologies that can be deployed to take advantage of a clean electric grid, including cold climate air source heat pumps (ccASHPs), ground source heat pumps, networked geothermal heating systems, heat pump water heaters, induction stoves/cooktops, and a range of industrial electrification technologies.
- **Biomethane (often called renewable natural gas or RNG)**. Biomethane is methane that is produced by decaying organic matter (e.g., from animal manure, crop residues, landfills and wastewater treatment plants). Biomethane is essentially chemically identical to fossil methane. Thus, burning of biomethane in a furnace produces just as much CO2e emissions as burning fossil methane. However, to the extent that emissions at the furnace "burner tip" are *offset* by elimination or reduction of emissions of methane – itself a potent greenhouse gas (GHG) – that otherwise would have been released to the atmosphere, the net effect of substituting biomethane for fossil methane can be a reduction in GHG emissions. As discussed further below, it is important to recognize that though biomethane is sometimes analyzed as if it is always zero emitting (simply because it is biogenic), the actual net effects on total CO2e emissions to the atmosphere varies widely depending on the source of the biomethane and existing regulations or standard business practices regarding methane emissions. Some forms of biomethane have net negative CO2e emissions (i.e., the benefits of eliminating methane emissions that would otherwise be emitted to the atmosphere are greater than the CO2 emissions that result from burning it); other sources of biomethane have emissions profiles not much better than fossil gas. Methane leaks in the gas transmission and distribution system – as well as leaks or incomplete combustion on the customer side of the meter – need to be reflected in estimates of any lifecycle GHG emission reductions associated with biomethane.
- **Hydrogen**. Hydrogen gas can potentially be substituted for fossil methane. The result can be substantial GHG emission reductions – if the hydrogen is produced through low or zero-GHG emitting processes. For example, when hydrogen is produced by electrolysis of water using renewable forms of electricity such as wind or solar power, no CO2e emissions are generated in

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[3] The estimated reduction from 2005 building sector emissions levels of 84 Mt is 37% - or a reduction to 53 Mt. However, emissions grew from 84 Mt to 91 Mt between 2005 and 2019. Thus, getting to 53 Mt would require a 42% reduction from the 2019 level of 91 Mt (https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/factsheet-02-buildings.pdf).
[4] Independent Electric System Operator (IESO), *Pathways to Decarbonization: A report to the Minister of Energy to evaluate a moratorium of new natural gas generation in Ontario and to develop a pathway to zero emissions in the electricity sector*, December 15, 2022, p. 6.
[5] https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity-regulation.html.

its production. This is known as "green hydrogen". Hydrogen can also be produced from fossil fuels, with a portion of the resulting CO2 combustion emissions captured and stored. This is known as "blue hydrogen". Note that there are always some GHG emissions associated with blue hydrogen because carbon capture and storage processes are never 100% and there are still fugitive emissions from the extraction and transportation of methane. Also note that hydrogen itself is an indirect greenhouse gas. Thus, leaks of hydrogen resulting from its production, transportation/distribution and movement through pipes and appliances in homes and businesses also need to be considered when assessing its lifecycle emission reduction potential.[6]

In addition to these fuel-switching options, energy efficiency or conservation can play an important role in reducing emissions in the near to medium term by reducing the amount of fossil fuel that needs to be burned to meet heating or other energy needs. In the longer-term, when fossil fuels need to have been fully replaced with low or zero-carbon alternatives, efficiency can still play an important role in reducing the costs of meeting heating and other energy needs by reducing the amount of alternative fuels (and related capital infrastructure) necessary to meet the energy needs of homes and businesses in a decarbonized future.

## 3. Electrification Dominates in Independent Decarbonization Pathways Studies

### A. Overview

Over the past decade there have been numerous studies examining different pathways for decarbonizing buildings and industry in Canada, the United States, Europe and globally. Such studies typically assess the costs and emissions impacts of different combinations of technologies and low or zero-carbon energy. There are many potential combinations of technologies and energy sources that can be and have been analyzed. However, at a high level, all such scenarios can generally be categorized as permutations and/or combinations of one or more of the following three approaches:

- **High levels of full electrification**. In these scenarios, the vast majority of heating, water heating and other residential and commercial end uses, as well as a significant portion of industrial end uses, are fully electrified with heat pumps and other advanced electric technologies. However, alternative fuels such as biomethane and/or green hydrogen are often assumed to be necessary for those industrial customers for whom electrification is not easy or feasible. Significant investment in energy efficiency is typically assumed to be necessary to partially reduce the magnitude of new electric generating, transmission and distribution capacity needed to meet customers' energy demands, particularly at peak hours on cold winter mornings.
- **Hybrid gas-electric solutions**. These scenarios still include substantial amounts of electrification. However, while there is typically assumed to be some full electrification, most homes and businesses are assumed to install hybrid heating systems in which electric heat pumps are paired with gas furnaces, with the heat pumps providing the vast majority of heating needs over the course of the winter and the gas furnaces turning on to meet peak heating needs during only the coldest days or hours of the year. Use of the gas distribution system to meet peak heating needs means less electric generating, transmission and distribution system capacity needs to be built. The vast majority of the gas supplied to meet peak winter heating

[6] Poore, Colton, "Switching to hydrogen fuel can prolong the methane problem", Princeton University, March 13, 2023 (https://engineering.princeton.edu/news/2023/03/13/switching-hydrogen-fuel-could-prolong-methane-problem).

loads is typically biomethane (sometimes augmented with very small amounts of hydrogen blending). As in the high electrification scenarios, those industrial customers who cannot easily electrify are assumed to switch to biomethane and/or green hydrogen. These scenarios also typically include significant energy efficiency investments, though sometimes the magnitude of those investments is assumed to be lower than in high electrification scenarios.

- **Mass distribution of 100% hydrogen.** This scenario assumes substantial amounts of electrification, but less than the two other scenarios because it is assumed that green and/or blue hydrogen will be distributed to large portions of existing residential and commercial gas customers, as well as to industrial customers. As with hybrid heating scenarios, significant investment in energy efficiency is typically assumed, but potentially at levels a little lower than for high electrification.

Most independently-conducted assessments of decarbonization pathways – i.e., those not sponsored by organizations with vested interests in the outcomes, such as gas utilities or organizations who are advocates for hydrogen – have concluded that high electrification pathways are the most likely and most cost-effective pathways, even in colder climates. That is the case for three recent studies for Canada, Quebec and New York, each of which is summarized below. While many if not most pathways assume 100% hydrogen is likely for some industrial customers, gas utility delivery of 100% hydrogen is generally not considered a realistic option for residential and commercial customers. A common gas utility vision of an alternative to high electrification is significant adoption of hybrid electric-gas heating systems. That was the conclusion of a recent study sponsored by the Massachusetts gas utilities, also summarized below.

## B. Canada Study (by Canadian Climate Institute)

In February 2021, the Canadian Institute for Climate Choices (since renamed the Canadian Climate Institute) released a report documenting the results of its assessment of a wide range of pathways to achieving net zero GHG emissions across all sectors of the Canadian economy.[7] The study assessed more than 60 different potential economy-wide pathways through technical modeling, literature review, and input from experts. It assessed macro-economic outcomes (e.g., changes to the structure of the economy), microeconomic outcomes (e.g., impacts on household energy use and costs), emissions impacts, and feasibility. The study authors also sought and received input and feedback from a range of perspectives, including “academics, practitioners, individual companies, industry associations, federal and subnational governments, Indigenous Peoples, and labour unions.”[8]

With respect to residential and commercial buildings, the report makes clear that electrification (and energy efficiency) will likely dominate decarbonization activity through 2035, with their model suggesting:

- sales of new electric heating systems overtaking sales of gas combustion furnaces between 2027 and 2032;
- the percentage of Canadian homes heating with heat pumps increases from about 2% in 2020 to between 15% and 20% by 2035; and

[7] Canadian Institute for Climate Choices, *Net Zero Future: Finding Our Way in the Global Transition*, February 2021 (https://climateinstitute.ca/reports/canadas-net-zero-future/).
[8] Ibid, p. 17.

- the percentage of Canadian homes heating with gas drops from a little over 70% in 2020 to between 50% and 55% by 2035.[9]

The study acknowledges that there is greater uncertainty with regard to the mix of technologies and fuels that will ultimately comprise the optimal solution to decarbonization by 2050. For example, it states that electric heating systems will heat between 52% and 100% of homes by 2050 (up from about 30% today), with the balance being met by wood (0% to 10%) and clean gases (0% to 40%).[10] All told, the study concludes that clean gases could potentially provide "a total amount of energy equivalent to 32 percent of today's natural gas demand in Canada's buildings."[11] However, the study notes that there are a number of barriers to clean gases playing even that large of a role. With respect to hydrogen, barriers include high costs, limits to the ability to blend hydrogen with methane, the "significant modifications to pipelines and distribution networks" required to carry more hydrogen than that, and the need to replace methane-burning equipment in homes and businesses with hydrogen-burning equipment. With respect to biomethane, the key barriers are both high cost and "limited" supplies of feedstock "making significant cost declines from economies of scale unlikely."[12] The bottom line is that "the future of clean gases in the buildings sector is complex and uncertain."[13]

### C. Quebec Study (by Dunsky)

In June of 2021 the Quebec Environment Ministry released a report documenting the results of a study designed to identify the lowest cost pathway to decarbonizing the province's economy.[14] As Figure 1 shows, the study concluded that natural gas use (systeme au gaz naturel) for residential space heating would be cut roughly in half by 2030 (relative to 2016) and essentially disappear by 2050. Fuel oil (systeme au mazout) and wood heating (poele a bois ou aux granules) also large disappear by 2050 in the decarbonization scenarios (Trajectories A, B, C and D). There is no hydrogen use in the residential sector in any scenario. Nor is there any appreciable use of biomethane. All space heating essentially becomes electric.

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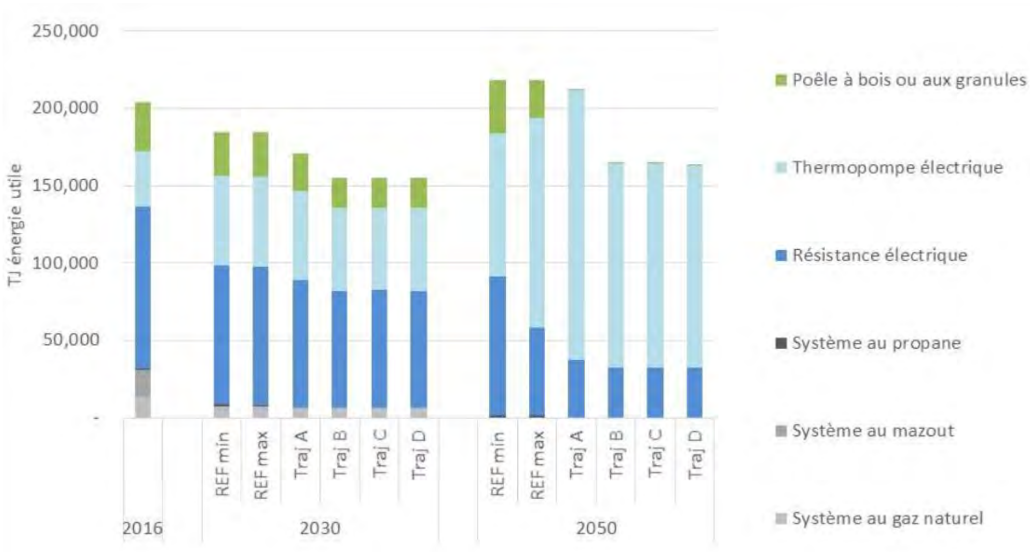
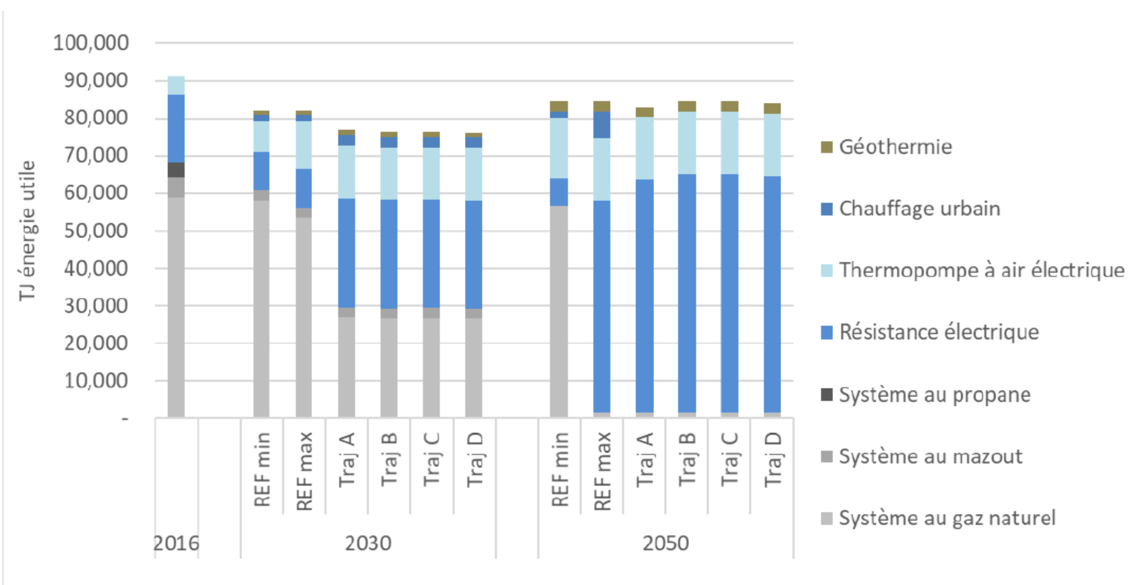
[9] Ibid, pp. 39-40.
[10] Ibid.
[11] Ibid., p. 43.
[12] Ibid., p. 44.
[13] Ibid.
[14] Dunsky, *Quebec GHG Emission Reduction Trajectories – 2030 and 2050*, prepared for the Ministry of Environment and the Fight Against Climate Change, June 2021 (available only in French at https://www.dunsky.com/wp-content/uploads/2021/09/Rapport_Final_Trajectoires_QC_2021.pdf)

*Figure 1: Quebec Decarbonization Study, Forecast Change in Residential Heating Fuel Mix[15]*




As Figure 2 shows, while the situation is slightly more variable in commercial and institutional buildings, there are still dramatic reductions in gas use for space heating in all decarbonization scenarios – on the order of 50% by 2030 (relative to 2016) and more than 95% reductions by 2050. As with residential buildings, there is no appreciable hydrogen or biomethane use.[16]

*Figure 2: Quebec Decarbonization Study, Commercial and Institutional Buildings Heating Fuel Mix[17]*

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[15] Ibid, p. 22.

[16] Though not clear from the graphic because it illustrates only changes in volumes of gas consumed through the existing natural gas distribution system, the very small amount of gas consumption in the decarbonized scenarios for 2050 may be biomethane.

[17] Dunsky, p. 22.

## D. New York Study (by E3)

In July of 2019, the state of New York enacted the Climate Leadership and Community Protection Act. The law requires the state to achieve a 40% reduction in GHG emissions (relative to 1990 levels) by 2030 and an 85% reduction by 2050. The law also created and instructed a 22-member Climate Action Council to develop and publish a plan with policy recommendations for meeting those emission reduction requirements. An initial draft plan was released in December 2021, following two years of investigation informed by input from seven sector-specific Advisory Panels, a Just Transition Working Group, stakeholders and the public. One key input to the development of the draft plan was a study (what the Council called an "integration analysis") outlining expected costs and benefits of different decarbonization pathways. The consulting firm Energy and Environmental Economics (E3) conducted the study.

The study started with the development of a business-as-usual (or reference case) scenario as well as a scenario based on initial recommendations of the Council's Advisory Panels. When analysis of that initial scenario suggested that the Council's recommendations were not enough to meet the state's GHG emission reduction goals, three additional scenarios were developed. Thus, the study ultimately assessed four GHG reduction scenarios (in addition to the reference case):

- **Scenario 1: Advisory Panel Recommendations** – including "rapid electrification of buildings and transportation, decarbonization of the power sector and ambitious reductions in non-combustion emissions";
- **Scenario 2: Strategic Use of Low-Carbon Fuels** – Advisory Panel recommendations adjusted for strategic use of biofuels as well as green hydrogen for difficult-to-electrify end uses.
- **Scenario 3: Accelerated Transition Away from Combustion** – Advisory Panel recommendations adjusted to accelerate electrification of buildings and transportation with a "very limited role" for biofuels and hydrogen.
- **Scenario 4: Beyond 85% Reduction** – Advisory Panel recommendations adjusted to include both accelerated electrification and targeted use of low-carbon fuels, plus additional reductions in "vehicle miles traveled" and innovation in methane abatement.[18]

The study found that Scenario 3, the scenario most emphasizing electrification and least invested in biofuels, had the lowest cost of the three scenarios that met the state's emission reduction requirements.[19] While Scenarios 2, 3 and 4 all produced greater benefits (in the form of GHG emission reductions and health improvements) than costs, net benefits were greatest for Scenario 3.

The study's results for the (residential and commercial) buildings sector include:

- "In all scenarios, electric heat pump space heating technology systems become the majority of new purchases by the late 2020s and no fossil-emitting appliances are sold after 2035."[20]

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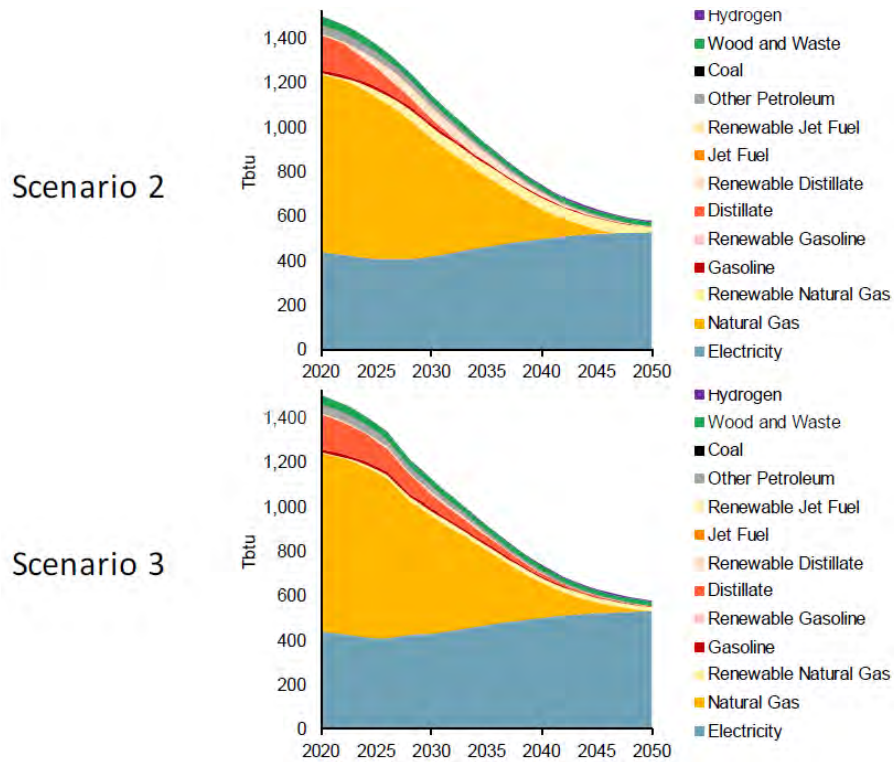
[18] Energy and Environmental Economics (E3), *Appendix G: Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan*, December 2022 (https://climate.ny.gov/resources/scoping-plan/), p. 14.
[19] The net present value (NPV) of the cost of Scenario 3 was $270 billion over the 2020 to 2050 analysis; the NPV of the cost of both Scenario 2 and Scenario 4 was $295 billion. Ibid, p. 8.
[20] Ibid., p. 31.

- The share of final energy demand met by electricity increases from 30% in 2020 to 89-92% in 2050 across scenarios 2 through 4.[21]
- Hybrid electric-gas heating systems play a limited role – 10% of heating systems by 2050, and only in Scenario 2.[22]
- The role of hydrogen in residential and commercial buildings is also very small, limited to the conversion of New York City's district heating system in Scenarios 2, 3 and 4.[23]

Figure 3 graphically illustrates these results for Scenarios 2 and 3.

*Figure 3: New York Climate Council Study, Forecast Fuel Mix for Buildings in Scenarios 2 and 3*[24]




The study results were more varied for industrial energy use, with energy efficiency, electrification, conversion to hydrogen, renewable natural gas, and carbon capture and storage for select industries (i.e., cement and iron and steel) playing roles in all scenarios. Hydrogen plays a bigger role in Scenario 2 while electrification plays a bigger role in Scenarios 3 and 4.[25]

## E. Massachusetts Study (by E3)

In October of 2020, the Massachusetts Department of Public utilities ordered "an investigation into the role of local natural gas distribution companies (LDCs) in the Commonwealth's goal to achieve net zero greenhouse gas emissions by 2050."[26] As part of that effort, the gas utilities hired Energy and

[21] Ibid.
[22] Ibid, p. 33 and Technical Supplemental Annex 2, "Scenario Detail" tab.
[23] Ibid.
[24] Ibid, p. 32 (this is a portion of the Figure 22 in the report).
[25] Ibid., pp. 56-57.
[26] https://thefutureofgas.com/overview

Environmental Economics (E3) to conduct a detailed assessment of a number of different pathways for decarbonizing fossil gas use in the state. The utilities also hired E3 and Scottmadden Management Consultants to develop a set of regulatory policy recommendations to support the energy transition.[27] This was not a truly independent study as it was sponsored by gas utilities with a vested interest in the continuation of the gas system. However, I discuss it here as it provides insight into the kind of decarbonization solutions that gas utilities are advocating for in some jurisdictions, which do not include anything close to the heavy reliance on 100% hydrogen as in Enbridge's vision.

The E3 decarbonization study ultimately included a reference case along with eight decarbonization scenarios. The assumptions regarding heating of residential and commercial buildings in those scenarios can be summarized as follows:[28]

- **Reference case**: 9% of residential homes and 10% of commercial buildings fully electrically heated in 2050, with most of the remainder using fossil gas.
- **High electrification**: virtually all buildings fully electrically heated by 2050, primarily through cold climate heat pumps.
- **Low electrification**: two-thirds of residential homes and 80% of commercial buildings fully electrically heated by 2050, mostly with cold climate air source heat pumps, with the remaining buildings primarily heating with renewable gas.
- **Interim 2030 Climate and Energy Plan**: comparable to high electrification scenario, but with accelerated adoption of heat pumps in the 2020s to meet the state's more aggressive 2030 emission reduction goals.
- **Hybrid electrification**: roughly 20% of residential and commercial buildings fully electrically heated by 2050, with virtually all of the rest adopting hybrid heating systems – e.g., cold climate heat pumps backed up by gas furnaces or boilers fueled by renewable gas.
- **Targeted electrification**: portions of the gas system decommissioned, roughly three-quarters of homes and nearly 85% of commercial buildings fully electrified by 2050, with most of the rest adopting hybrid heating systems fueled by renewable gas.
- **Networked geothermal**: networked geothermal electric heat wherever feasible – i.e., for about one-quarter of residential homes and half of commercial buildings by 2050 - with the remainder either fully electrified with air source heat pumps, ground source heat pumps or electric resistance heat (collectively about half of residential buildings and 35% of commercial buildings) or fueled by renewable gas (about one-quarter of homes and 15% of commercial buildings).
- **Efficient gas equipment**: roughly one-quarter of residential homes and 13% of commercial buildings fully electrified with most of the rest adopting high efficiency gas appliances (mostly gas heat pumps) fueled by renewable gas.
- **100% gas decommissioning**: 100% electrification of buildings by 2050 through a combination of networked geothermal, cold climate air source heat pumps and ground source heat pumps.

[27] Both of these reports can be found in the "Customer Resources and Stakeholder Engagement Process" section of https://thefutureofgas.com/sep.

[28] See E3 and Scottmaden, *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals, Independent Consultant Report, Technical Analysis of Decarbonization Pathways*, March 18, 2022, pp. 29-32 for high level descriptions of the scenarios, with details on assumed heating market shares by scenario from the Excel filed serving as Appendix 4, "Scenario parameters (detail)" tab.

In addition, in all decarbonization scenarios there is significant investment in energy efficiency, particularly building envelop efficiency. In all decarbonization scenarios all gas consumption is assumed to be renewable gas, which is primarily biomethane. The study assumed that when demand for gas outstripped available supply of biomethane, even more expensive synthetically produced methane could fill the gap. The study also assumed green hydrogen blending with methane – up to 20% by volume and 7% by energy content – was feasible. No scenario included either blue hydrogen or 100% hydrogen delivered to residential or commercial buildings, though some scenarios included 100% hydrogen delivery to at least portions of the industrial sector.

The study found the hybrid electrification scenario – which, as discussed below, still results in a 73% reduction in annual gas throughput and about a one-third decline in peak demand for gas by residential, commercial and industrial customers – to be the lowest cost. The high electrification scenario was found to be about 25% more expensive.[29] However, many parties raised concerns about a number of study assumptions that appeared to bias the results in favor of continued use of the gas system, including unreasonably high assumptions about the future cost of cold climate heat pumps; significantly understating cost savings from pruning of the gas distribution system, unrealistically optimistic assumptions about the availability of biomethane (RNG); assuming market clearing prices for biomethane would not be affected by higher market prices paid for synthetically produced methane; and failing to account for the fully lifecycle emissions impacts of producing, transporting and burning both biomethane and synthetically produced methane.[30] I was highly involved in this proceeding on behalf of a client and I believe it is likely that much higher levels of full electrification would have been found to be a lower cost pathway if these biases had been corrected.

### F. Commonalities Across Studies

There are a number of commonalities to the conclusions of the studies discussed above. Chief among them are:

- Significant investments in building envelop energy efficiency upgrades – much broader and deeper than current utility efficiency programs are typically achieving – are cost-effective and critically important in every scenario.
- Significant levels of electrification are necessary, because of the limited availability of (and competing demands/uses for) biomethane, and the practical constraints of mass delivery of hydrogen and its cost.
- A significant portion of homes and businesses will become all-electric – meeting heating (and other end use needs) without any gas back-up – in every scenario. While that portion is obviously much smaller in scenarios emphasizing hybrid heating systems, it is still non-trivial.
- Delivery of 100% hydrogen delivery to residential and commercial buildings is generally seen as so unrealistic that it typically isn't even analyzed.
- Biomethane and/or 100% hydrogen will be necessary to decarbonize segments of the industrial sector.

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[29] E3 and Scottmaden, *Technical Analysis of Decarbonization Pathways*, p. 13.
[30] For example, see Sierra Club's comments at (https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14922666).

As Table 1 shows, one result that flows from these conclusions is that annual gas energy throughput is going to decline dramatically – by 70% to 90% or more – over the next several decades.[31]

*Table 1: Decarbonization Study Conclusions on Reductions in Annual Gas Energy Throughput by 2050[32]*

| | Canada | Quebec | New York (scenarios 2-4) | Massachusetts Hybrid Electric Scenario | Massachusetts High Electric Scenario |
|---|---|---|---|---|---|
| **Throughput Reduction:** | **68% to 100%** | **~75% to 80%** | **91% to 94%** | **73%** | **84%** |
| **Sectors Applicable to:** | Buildings | Buildings & Industry | Buildings & Industry | Buildings & Industry | Buildings & Industry |
| **Relative to Base Year of:** | 2020 | 2016 | 2020 | 2020 | 2020 |

Though decarbonization studies typically report on changes in both annual gas throughput and both annual electricity production and peak electricity demand, they do not always report on changes in gas peak demand. For the three independent studies noted above for Canada, Quebec, and New York, one can infer that the peak gas demand declines significantly because they mainly involve full electrification of home heating.

The Massachusetts' study is the only one of the four studies reviewed above that found hybrid heating to be the most cost-effective. Nevertheless, it too suggests that reductions in peak demand for gas from buildings and industry is inevitable if the economy is to be fully decarbonized by 2050. The declines are most dramatic in the "high electrification" scenario – on the order of a 90% reduction in peak day demand from residential, commercial and industrial customers by 2050 (relative to 2020 levels). However, even under the hybrid electrification scenario in which the majority of current customers use gas to meet peak heating demand on the coldest days and hours of the year, demand from all customers other than electric generators is about one-third lower in 2050 than in 2020.[33] This suggests that the energy transition is likely to not only eliminate future needs for capacity upgrades to the gas distribution system but to also reduce the need for and usefulness of much of the existing gas distribution system.[34]

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[31] Studies typically report changes in throughput just on an energy basis and not on a volumetric basis. Reductions on a volumetric basis can be smaller, to the extent that hydrogen – which carries only about 30% as much energy per cubic meter as methane – is utilized. However, even volumetric reductions will be substantial. For example, the reduction in annual *volumes* of gas consumed in New York in 2050 will still be 74% to 85% lower than in 2020 under the referenced decarbonization scenarios. That estimate was computed based on the forecast mix of biomethane and hydrogen (with hydrogen being the majority of forecast gas energy used in 2050) from the New York study's Technical Supplement Annex 2 (key drivers-outputs).

[32] Canadian Institute for Climate Choices, p. 40 (electric heat can comprise up to 100% of residential heating) and p. 43 ("clean gases could potentially provide a total amount of energy equivalent to 32% of today's natural gas demand from Canada's buildings"); Dunsky, p. 13; E3, *Appendix G: Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan*, Tech Supplement Annex 2, "gas throughput" tab; E3 and Scottmaden, *Technical Analysis of Decarbonization Pathways*, p. 15.

[33] E3 and Scottmaden, *Technical Analysis of Decarbonization Pathways*, p. 65. Peak day demand also fell under the "efficient gas equipment" scenario, by about 25% by 2050.

[34] It should be noted that the Massachusetts study also found that total peak day gas demand would increase by 15-20% relative to 2020 by 2050 under the "high electrification" scenario because of significant use of gas generation to meet electric peak demands. This suggests that *some* gas infrastructure *may* need to be enhanced or developed. However, the extent to which that is the case may depend on the type of clean gas being used for peak

## 4. Practical Reasons to Expect Electrification Will Dominate Gas Decarbonization

In addition to potential cost advantages, a number of practical and market realities support the common conclusion of independent studies that electrification will dominate decarbonization of residential and commercial buildings and play an important role in decarbonizing industry.

### A. Much Less Technological Uncertainty for Electrification Pathways

Electrification can be accomplished with existing technologies whose performance and costs are not only well known, but in many cases demonstrably improving over time. This is true of both renewable electric generation technology (e.g., wind and solar) and technology that needs to be deployed in homes and businesses (e.g., cold climate heat pumps).

This is not to say that there is absolute certainty regarding every element of a decarbonization pathway that relies heavily on electrification. However, the uncertainties are much smaller than for pathways relying much more heavily on clean gases. For example, we now have more than a decade of experience with the use of electric cold climate heat pumps, with sales growing quickly in several jurisdictions. For example, in the northeastern state of Maine, which has a population of a little under 1.4 million, more than 24,000 heat pumps were installed in just 2022.[35] On a per capita basis, that would be roughly equivalent to the installation of a quarter million heat pumps per year in Ontario. In contrast, gas heat pumps, which some studies assume would be critically important to reliance on clean gases are not even readily commercially available today, at least not for residential applications.

Similarly, hydrogen burning appliances cannot be purchased today; nor is there clarity on the likely leakage risks associated with hydrogen distribution pipes, let alone whether pipes that are currently carrying methane from customers' meters through their homes and businesses could carry hydrogen without substantial leakage and related safety risks. Indeed, a report by consultants involved in the design of a hydrogen pilot project in the United Kingdom suggests that rooms with hydrogen-burning equipment or substantial pipework "should have non-closable vents" with the equivalent of 100 square centimeters (or four inches by four inches square) of ventilation, potentially requiring the drilling of holes in walls, in order to mitigate the risk of hydrogen explosions.[36] The consultants and gas utility (Cadent Gas) subsequently suggested that most homes in the neighborhood in which a potential pilot hydrogen heating project would be initiated will not require the maximum ventilation because of how drafty or leaky much of the housing stock already is. The notion that one would want to rely on the

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electricity capacity (biomethane or hydrogen) and the proximity of that fuel source to the siting of new gas-fired peaking power plants. In any case, to the extent that peak demand for peak gases for electric power plants would require new gas pipe, that investment will likely be very different – e.g., more transmission than distribution or distribution dedicated solely to electric power generators – than investments historically made by gas utilities to meet growing residential and/or commercial peak loads.

[35] Mitchell, Jennifer, "Maine Is On Track To Meet Its Goal of 100,000 New Heat Pumps Installed By 2025, Mills Says", published by Maine Public, September 24, 2021 (https://www.mainepublic.org/environment-and-outdoors/2021-09-24/maine-is-on-track-to-meet-its-goal-of-100-000-new-heat-pumps-installed-by-2025-mills-says).

[36] Gatten, Emma, "Hydrogen boilers might need 'four-inch holes in walls to prevent explosions' – Government-backed safety report recommends extra ventilation ahead of pilot scheme to run eco-friendly heating systems", published online in The Telegraph, 3 March 2023 (https://12ft.io/proxy?q=https%3A%2F%2Fwww.telegraph.co.uk%2Fnews%2F2023%2F03%2F03%2Fhydrogen-boilers-might-need-four-inch-holes-walls-prevent-explosions%2F%23%3A%7E%3Atext%3DL%E2%80%A6).

leakiness of existing homes – or to intentionally make them more leaky – in order to lessen the risk of hydrogen explosions is highly problematic, especially for colder climates like Ontario's.

### B. No Practical Limits to Electrification Whereas RNG Supply is Very Limited

There are no practical limits to the ability to generate clean electricity. In contrast, the availability of biomethane (or RNG) is very limited. For example, a 2020 Torchlight Bioresources study completed for Natural Resources Canada found that the feasible annual RNG potential for Canada was only about 155 PJ which is equivalent to only 3.3% of Canada's current fossil methane consumption.[37] Moreover, it is not reasonable to assume that all feasible biomethane potential will be used to displace fossil methane currently used for heating buildings. Indeed, the Torchlight study itself concludes that "RNG is more price competitive with transportation fuels than with natural gas."[38]

Enbridge and its consultant, Guidehouse, have suggested that the theoretical "technical potential", rather than "feasible potential", should be considered. As discussed later in this report, that is a completely unreasonable position. As the Torchlight study itself states, and as discussed further later in this report, most of the technical potential will not be available for displacing fossil methane because of "competing uses for feedstock, seasonal feedstock supply risk, logistical constraints including the distance between many feedstocks and the closest natural gas pipeline, precommercial technologies for wood-based production and the high cost of RNG production from most pathways."[39] However, even if one ignores all of those limitations – as Enbridge and Guidehouse have – the total Canadian technical potential is equivalent to only about 17% of current Canadian consumption of fossil methane.[40]

### C. Electrification Can Be Piecemeal, 100% Hydrogen Delivery Cannot Be (without New Pipes)

Adding electric loads to homes and businesses is fairly straightforward. Everyone with fossil gas service today also has electricity service. While some customers will require upgrades to electric panels to accommodate heat pumps, many will not. In any case, such upgrades are well understood and relatively modest in cost. And while substations and other elements of the electric distribution system may need to have capacity upgrades when enough customers electrify, some parts of the electric distribution system will likely be able to accommodate significant electrification without such upgrades, and the upgrades that are required will not need to all be made at the same time.

In contrast, there is currently no delivery system for bringing 100% hydrogen to homes and businesses as would be necessary for Enbridge's "vision" and Guidehouse's gas-centric decarbonization scenario. While some methane pipe may theoretically or technically be able to carry hydrogen, it is hard to imagine how conversion of the current methane distribution system to carrying 100% hydrogen distribution could realistically unfold.

In order to switch from methane to 100% hydrogen much of Enbridge's existing distribution pipe would need to be replaced, or if possible, treated or conditioned.[41] That would seem to require that methane

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[37] Stephen, Jamie et al. (TorchLight Bioresources), Renewable Natural Gas (Biomethane) Feedstock Potential in Canada, Final Report, funded by Natural Resources Canada, March 2020, p. iii.
[38] Ibid, p. 47.
[39] Ibid, p. 54.
[40] Ibid, p. 54.
[41] Guidehouse suggests that Enbridge's gas pipeline network "is ideally suited to be repurposed to a hydrogen network, as the province's newer pipelines, typically made of polyethylene, are already hydrogen-ready."

delivery be cut off to customers downstream of the conversion until the treatment is completed. What would customers be expected to use to heat water, cook food, etc. while that is happening?

Much more importantly, every methane-burning appliance (furnace, boiler, water heater, stove, dryer, etc.) downstream of the pipe being converted from methane-carrying to 100% hydrogen-carrying would need to have been converted to hydrogen burning before the utility distribution system switch-over occurs. All in-home piping would also have to be hydrogen-ready. Enbridge and its consultants have suggested that this can be accomplished if customers install hydrogen-ready equipment when existing equipment reaches the end of its useful life.[42] While there is no reason to expect that result to naturally emerge in the market, government policy could require all new gas-burning appliances (and the in-home piping serving them) to be "hydrogen-ready". However, there are at least three major problems with that vision.

- First, it is important to recognize that "hydrogen-ready" does not mean that a furnace or water heater or cooktop can instantaneously switch from burning methane to burning hydrogen. There are components of each appliance that will need to be switched at the time of conversion from methane pipe to 100% hydrogen pipe. That will require going into every home and business to make such conversions. How would Enbridge ensure it could even get into every home and business?
- Second, gas furnaces have an average measure life of about 18 years and gas boilers have an average measure life of 25 years.[43] Importantly, those are *averages*. Some furnaces last 25 to 30 years and some boilers last longer than that. Thus, even if government required all new gas-burning appliances to be hydrogen-ready as early as 2025, it is unlikely that *all* gas-burning appliances in a given community or neighborhood will be hydrogen-ready before 2050 if we relied exclusively on natural equipment turnover to reach that state. If we do not rely on natural equipment turnover to get to a fully hydrogen-ready state in all homes and businesses, there will be huge costs incurred to encourage and/or force customers to replace furnaces, boilers and/or other appliances before they planned to do so.
- Third, if Enbridge is prepared to switch a pipe carrying methane to 10,000 or 100,000 homes and businesses to 100% hydrogen, how will it know whether every single one of the tens or hundreds of thousands of individual appliances served by that pipe has been replaced with something hydrogen-ready so that it can switch to 100% hydrogen with minimum safety risk?

Another important issue is that, because hydrogen is less dense than methane, a given diameter of pipe can deliver only about 30% as much hydrogen energy as methane energy. That suggests that existing methane pipe could only be used to deliver hydrogen if peak demand from customers connected to the pipe is collectively reduced by 70%.

All of this suggests that the only plausible way to deliver 100% hydrogen on a mass scale to residential and small to medium business customers is to build a new hydrogen pipe distribution system in parallel to the existing methane distribution system. That would allow a gradual, customer-by-customer switch

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(E1/T10/S5/Attachment 2, p. 60 of 88). However, only about 40% of Enbridge's distribution pipe is made from polyethylene (response to GEC-23b).

[42] Response to SEC-41(b).

[43] These are commonly assumed measure lives in utility DSM programs. For example, see Enbridge EB-2021-0002 Interrogatory Response I.5.EGI.GEC.9_Attachment 2, Tab Union-2019 rows 19 and 20.

from methane-burning to hydrogen burning just as electrification can proceed customer-by-customer.[44] However, the cost of building and operating a parallel 100% hydrogen distribution system – while still operating and maintaining a methane distribution system – would be prohibitive.

## 5. Customer Economics of Electrification Are Good Today, Likely to Remain Good

### A. Customer Economics of Electrification Without New Decarbonization Requirements

As the discussion above suggests, the energy transition is going to require significant electrification of current fossil gas use, with independent assessments generally finding that extremely high levels of full electrification will be the most economic and most practical way to decarbonize buildings in the future. An assessment of the customer economics of electrification today could shed some light on how quickly the energy transition may begin to gain steam.

To that end, I assessed the impacts of electrifying a single-family Toronto home that is currently using gas. I found that a customer would begin saving on energy costs immediately and would save $16,749 (NPV) over the lifetime of the equipment if they electrify.

To represent the average home, I assume that 82% of such homes also use gas for water heating, 16% for drying and 30% for cooking.[45] I assumed average consumption levels for each end use; typical costs (including availability of federal Greener Home rebates), efficiencies (typically Energy Star levels) and measure lives for efficient gas and electric equipment;[46] and current (winter of 2022-2023) gas and electricity prices, adjusted into the future only for the impact of the increasing federal carbon tax. For heating equipment, I compare the purchase of a 95% gas furnace and SEER 14 central air conditioner to a cold climate air source heat pump (ccASHP) with a seasonal average coefficient of performance of 2.84 in 2023[47] and a cooling efficiency rating of SEER 18.[48] I assume that the customer fully electrifies at the time that it would otherwise be replacing both its gas furnace and central air conditioner. This requires additional capital costs for a new electric heat pump water heater, new electric stove and new electric dryer – costs that would not be incurred for another seven or eight years if the customer continued to use gas equipment for such end uses.[49] On the other hand, such a complete fuel-switch would enable customers to eliminate not only all variable gas charges, but also all fixed monthly gas charges. My results are expressed in 18-year net present value (NPV) terms, since 18 years is the assumed life of both gas furnaces and cold climate air source heat pumps. Because dryers, stoves and water heaters have

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[44] Note that is still not as flexible as electrification, which can occur not only customer-by-customer, but even appliance-by-appliance.

[45] Response to GEC-61, Attachment 1.

[46] Note that to represent the average home, I multiply water heating, drying and cooking equipment costs and energy costs by the assumed saturation of those gas appliances.

[47] This is the same assumption as Guidehouse used for new ccASHPs purchased in 2023 in its Pathway to Net Zero study for Enbridge (JT1.28, Attachment 3, "HP Turnover" tab).

[48] New ccASHPs tend to be much more efficient at cooling that the vast majority of new central air conditioners. In a review I conducted in the Summer of 2022 of nearly 400 cold climate, centrally-ducted ccASHPs listed by the Northeast Energy Efficiency Partnerships (https://ashp.neep.org/#!/product_list/) with heating capacities between 35,000 and 40,000 Btuh at 5 F, only about 3.5% had a SEER rating below 17 and more than half had a SEER rating of 20 or higher.

[49] I assume that the average stove lasts 15 (gas) to17 (electric) years, the average water heater lasts about 15 years and average dryer lasts 13 years, so on average (i.e., assuming the average appliance is roughly halfway through their useful life), an existing home would need to replace those pieces of gas equipment (absent an electrification investment) in roughly 7 to 8 years.

slightly shorter lifespans, the analysis accounts for a portion of future replacement costs for those appliances. I also assess how the economics would change in 2030, assuming the only difference between now and then are increases in the federal carbon tax and small improvements in cost and efficiency of cold climate air source heat pumps.

As Table 2 shows, full electrification in 2023 of a Toronto single-family home currently using gas for heating, water heating, cooking and drying would reduce energy bills by about 37% in the first year and by 46% over the 18-year life of a new cold climate heat pump. A similar electrification decision in 2030 would cut energy bills approximately in half, both in the first year and over the long-term.

*Table 2: Change in Energy Bills from Electrification of Single-Family Toronto Home, Today and in 2030*

| | without Electrification | with Electrification | $ Change | % Change |
|---|---|---|---|---|
| **2023 Electrification** | | | | |
| 1st Year (2023) Energy Bills | $1,841 | $1,158 | ($683) | -37% |
| 18-Year NPV of Energy Bills | $28,268 | $15,249 | ($13,018) | -46% |
| **2030 Electrification** | | | | |
| 1st Year (2030) Energy Bills | $2,260 | $1,126 | ($1,134) | -50% |
| 18-Year NPV of Energy Bills | $29,760 | $14,826 | ($14,933) | -50% |

As

Table 3 shows, with application of federal Greener Homes and Enbridge rebates, the NPV of the cost of installing new electric equipment – *even though any water heater, stove and dryer would be installed much sooner than gas replacements would have been required* – would be less than the NPV of the cost of equivalent gas equipment. The total 18-year NPV of costs for both energy and equipment would be about 43% less for electrification undertaken in 2023 – and about 47% less for electrification undertaken in 2030 – than continued use of gas.

*Table 3: Change in Total Cost from Electrification of Single-Family Toronto Home, Today and in 2030*

| | without Electrification | with Electrification | $ Change | % Change |
|---|---|---|---|---|
| **2023 Electrification** | | | | |
| 18-Year NPV of Energy Bills | $28,268 | $15,249 | ($13,018) | -46% |
| 18-Year NPV of Equipment Costs | $10,264 | $6,534 | ($3,730) | -36% |
| 18-Year NPV of Total Costs | $38,531 | $21,783 | ($16,749) | -43% |
| **2030 Electrification** | | | | |
| 18-Year NPV of Energy Bills | $29,760 | $14,826 | ($14,933) | -50% |
| 18-Year NPV of Equipment Costs | $10,264 | $6,366 | ($3,898) | -38% |
| 18-Year NPV of Total Costs | $40,023 | $21,192 | ($18,831) | -47% |

I tested the sensitivity of these results to several assumptions. Results of those sensitivity tests are as follows:

- If federal Greener Home rebates are not applied, the NPV of capital costs of electrification are about $4300 higher than for non-electrification in 2023 (about $3900 higher in 2030). This is largely because of the need to invest in a new water heater, stove and dryer sooner than would be necessary if just replacing current gas equipment when it reaches the end of its life. However, the substantial energy bill savings are unaffected by this change so total costs are still 23-28% lower with electrification.
- If I use ICF's 4th Quarter 2022 forecasts of gas commodity prices – i.e., dropping by almost 50% in inflation-adjusted terms by 2028, then gradually climbing back up again (but never again reaching prices experienced this past winter) – energy bill savings are only slightly lower (e.g., 44% savings over an 18-year period starting in 2023 instead of 46%), with total savings not changing considerably.
- Excluding assumed ccASHP efficiency and cost improvement assumptions has no effect on 2023 NPVs and reduces total cost savings from a 2030 installation by just a couple of percentage points. This is partly because I used Guidehouse's conservative assumptions about the likely magnitude of future ccASHP technology and market improvements.
- If I assume that the season average heating efficiency of ccASHPs is 15% worse than assumed by Guidehouse (i.e., season average COP of 2.41 instead of 2.84), the 18-year NPV of energy bill savings from a 2023 installation decline from 46% to 38% - i.e., still substantial; the NPV of total (energy plus capital) costs declines from 43% to 38% - also still substantial.
- My analysis did not assume and an electric panel upgrade would be required. Some homes will need such upgrades; others will not. However, the cost of panel upgrades - $2000 or less on average[50] – would not significantly change the conclusion that electrification is very cost-effective for customers.

The conclusion that electrification is cost-effective for customers today is very robust.

## B. Customer Economics of Electrification in a Decarbonized Future

Developing specific estimates of the cost-effectiveness of customers investing in electrification at various points between 2023 and 2050 in a future in which policies and markets drive full decarbonization of buildings by 2050 would require detailed economy decarbonization modeling that is well beyond the scope of this report. However, evidence available from other modeling efforts and our understanding of likely future prices for biomethane suggest that the customer economics of electrification will actually become more compelling than they are today.

Consider the comparison in Table 4. The first two columns compare (1) the current variable cost to residential customers of fossil gas with a $170/tonne carbon tax to (2) the current variable cost of electricity to residential customers in Toronto. While electricity is more expensive per unit of energy delivered to the home, it is much less expensive per unit of heat produced for the home because electric heat pumps are about three times more efficient than efficient gas furnaces. In terms of dollars per unit of heat produced for the home, fossil gas would be 71% more expensive even if no new policies requiring the decarbonization of the gas sector are adopted. The second two columns provide a similar

[50] EB-2021-0002 Exhibit I.10h.EGI.Staff.77, p. 10.

comparison, but under a scenario in which there is a policy requiring net zero emissions by 2050, with customers either consuming RNG that costs $62/GJ (but no carbon tax) or electrifying and paying 25% higher electric rates than today. $62/GJ is the cost of the most expensive source of RNG in the Torchlight study upon which Enbridge has relied for its estimates of biomethane (or RNG) potential.[51] As with all commodity markets, the most expensive source of RNG will ultimately set the market clearing price for all RNG. The 25% increase in electric rates is the mid-point of the range of increases by 2050 that the IESO recently estimated for a scenario with very high levels of electrification of buildings.[52]

*Table 4: Volumetric Cost of RNG Heat vs. High Electrification Heat*

| | | **Without New Decarbonization Policy** | | **With Full Decarbonization Policy** | |
|---|---|---|---|---|---|
| | | Fossil Gas vs. Electric Heat | | Biogas vs. Electric Heat | |
| | | $170/tonne Carbon Tax | | $62/GJ RNG | |
| | | No Further Decarb Policy | | IESO 25% Rate Increase w/Hi Electrification | |
| | | **Fossil Gas Furnace** | **Electric Heat Pump** | **RNG Furnace** | **Electric Heat Pump** |
| $/m3 or $/kWh *input* | | | | | |
| | Commodity | $0.22 | | $2.41 | |
| | Transportation | $0.05 | | $0.05 | |
| | Distribution | $0.12 | | $0.12 | |
| | Carbon Tax | $0.29 | | $0.00 | |
| | HST | $0.09 | | $0.34 | |
| | Total | $0.76 | $0.13 | $2.91 | $0.17 |
| $/GJ of Energy *Input* | | $20.49 | $37.05 | $78.25 | $46.31 |
| Heating Efficiency | | 95% | 293% | 95% | 293% |
| $/GJ of Heat *Output* | | **$21.57** | **$12.65** | **$82.37** | **$15.81** |
| Gas Price as % of Electric | | 171% | | 521% | |

Put simply, the current cost advantages of electrifying building space heating will be substantially greater in a decarbonized future. The incremental cost of RNG (relative to fossil gas plus a carbon tax) is simply much greater than the increase in the price of electricity that will be necessary to grow the electric grid so that it can serve electrified buildings.

Moreover, the comparison in Table 4 likely understates the extent to which the economics of electrification will improve in a decarbonized future.

- First, the analysis only compares the variable or volumetric cost per GJ of gas and electric heat. Customers who fully electrify will also eliminate fixed monthly gas charges.

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[51] Torchlight, p. 44. Figure 26 shows costs which I assumed to be in 2020 dollars. I have increased them by 12.45% to express them in 2023 dollars per a consumer price index calculated available from the Bank of Canada (https://www.bankofcanada.ca/rates/related/inflation-calculator/).

[52] IESO, Pathways to Decarbonization: A report to the Minister of Energy to evaluate a moratorium on new natural gas generation in Ontario and to develop a pathway to zero emissions in the electricity sector, December 15, 2022 (https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization), p. 32. The 20-30% increase is inclusive of costs of adding peak generating capacity, transmission capacity and distribution capacity. Though the IESO only explicitly modeled generation and transmission costs, it added a 25% "contingency" cost to its estimates which it says is intended, in part, "to capture out-of-scope costs (e.g., the build-out of distribution infrastructure…)." (p. 17).

- Second, the analysis holds transportation and distribution charges for gas constant at today's prices. However, as Table 1 above shows, decarbonization studies suggest total gas energy throughput will decline by 70-90% or more by 2050. Even the Guidehouse pathways study commissioned by Enbridge suggests that gas energy sales to residential and commercial customers will be reduced by about 50% (Diversified scenario) to nearly 90% (Electrification scenario) by 2050.[53] As gas sales decline, rates will go up because the past capital investments, as well as the fixed cost of operating the system, will have to spread over a smaller volume of sales.
- Third, the analysis does not account for the fact that RNG will not produce 100% reductions in lifecycle emissions, so additional emission reduction investments will need to be made on the gas system. In addition to those factors, any decarbonization approach that relies on delivery of 100% hydrogen to residential and commercial customers will result in huge additional gas distribution system costs that will need to be recovered in rates.

My conclusion that the customer economics of electrification will improve in a decarbonized future is consistent with the results of the recent decarbonization study funded by the Massachusetts gas utilities – despite its significant biofuel biases. For example, that study found that low-income energy burdens (the percent of income required to pay energy bills) would increase less – in most cases significantly less – for those customers who become all-electric than for those customers who remain on the gas system. Moreover, it found that energy burdens would be lowest – and lower than today – for customers who fully electrified under a high electrification scenario.[54]

## 6. Study Used by Enbridge to Support Vision of Hydrogen Future Is Fatally Flawed

### A. Overview

Enbridge commissioned Guidehouse to conduct a decarbonization study that analyzed two pathways to net zero GHG emissions in Ontario by 2050. One pathway emphasized significant levels of electrification of buildings, but still maintained the entire existing gas system. The other included some electrification, but placed greater emphasis on substitution with biomethane and a significant commitment to delivering 100% hydrogen (instead of methane) to large numbers of residential and commercial customers. The initially filed study concluded that the so-called "Electrification scenario" would be $181 billion more expensive than the high gas scenario (what Guidehouse called the "Diversified scenario"). Following interrogatories, Guidehouse identified errors and reduced the gap to $167 billion. Following the technical conference and the OEB order to release the underlying model details, Guidehouse identified further problems and updates, which reduced the gap to $41 billion, a full $140 billion difference from its original report.

While the corrections that Guidehouse has made to its analysis are important, a number of significant problems remain, many if not all of which are likely to bias results against electrification and in favor of gaseous fuels.[55] Thus, the study remains fundamentally flawed and its conclusions remain highly misleading. If even one or a few of those errors are corrected, the high gas scenario is tens of billions of

[53] E1/T10/S5 Attachment 2, p. 29 of 86.
[54] E3 and Scottmaden, *Technical Analysis of Decarbonization Pathways*, p. 17.
[55] Note that my review has been necessarily less than comprehensive, given both the number of assumptions that have gone into the model and Guidehouse's inability to make the model available for us to run to better understand how it works.

dollars more expensive than the scenario emphasizing higher levels of electrification. In the following subsections, I discuss several key concerns.

## B. Inappropriate Use of Higher Carbon Emissions Cost for Electrification Scenario

Guidehouse treats carbon taxes as a cost. However, carbon taxes are not costs in societal-level analyses such as this one.[56] Rather, they are transfer payments. That is always true in societal cost-effectiveness assessments, but even more obvious in this case because carbon taxes are returned to Ontarians through direct payments.[57] As Table 5 shows, Guidehouse's mistreatment of carbon taxes in its analysis is particularly problematic because it assumed a much higher carbon price – on the order of 70% higher after 2030 – would get applied to the "Electrification" scenario than to the "Diversified" scenario.[58]

*Table 5: Guidehouse Assumed Cost of Carbon Emissions (nominal $/tCO2e)*[59]

| | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|
| Diversified Scenario | $28 | $166 | $206 | $251 |
| Electrification Scenario | $28 | $282 | $351 | $427 |

This fundamentally distorts the results of Guidehouse's analysis. As noted above, after its most recent changes, Guidehouse is estimating that its Electrification scenario is $41 billion more expensive than its so-called Diversified scenario. However, that includes $57 billion in supposedly higher carbon emissions costs for the electrification scenario.[60] In other words, ***Guidehouse's Electrification scenario would be lower cost than its Diversified scenario if the only change made to its analysis was to use the same carbon price in both scenarios*** (or if no carbon cost was included at all).

If the cost of carbon emissions is to be included in a societal cost assessment of decarbonization pathways, that cost should be an estimate of the damage caused by each tonne of carbon emissions. The environmental, public health and other damage caused by a tonne of carbon emissions is the same regardless of the source of the emissions or the scenario under which the emissions took place. So the societal cost of carbon is the same for all emissions under all scenarios.

[56] In its response to GEC-15c, Guidehouse itself acknowledges that its analysis assesses economics from a societal perspective: "the Total Energy System Costs in the P2NZ represent ***total costs to society*** and do not reflect the retail energy prices customers would pay." (emphasis added)

[57] https://www.canada.ca/en/department-finance/news/2022/03/climate-action-incentive-payment-amounts-for-2022-23.html.

[58] Guidehouse says it did this because carbon taxes would need to be higher to drive high levels of electrification. [response to GEC-24(b)] Aside from the huge and fundamental methodological problem of treating carbon taxes as societal costs, the notion that carbon taxes would need to be higher to drive electrification than to drive investment in gas heat pumps at mass scale (when they aren't really even available in the market today), gas-burning equipment capable of burning hydrogen, and other components of a decarbonization pathway the emphasizes continued burning of gaseous fuels is, at best, completely unsubstantiated. As explained in the previous section of this report, the customer economics of electrification are already compelling and are likely to get substantially better in a decarbonizing future. Moreover, carbon taxes are but one instrument for advancing decarbonization investments. Government can also regulate the types of heating equipment sold in the market, provide rebates for lower emitting equipment (as the federal Greener Home program is currently providing for electric heat pumps), etc.

[59] JT1.28-Attachment 5, "Carbon Costs" tab, rows 11-13.

[60] E1/T10/S5 Attachment 2, p. 46 of

It is worth noting that Guidehouse's analysis concluded that carbon emissions in the 2030s and 2040s would actually be *lower* under the electrification scenario than under diversified scenario.[61] In other words, if the same societal price of carbon was used in both scenarios, the result the electrification scenario would have looked even more favorable than it does when just eliminating the extra $57 billion in cost that Guidehouse inappropriately assigned to it. In fact, simplified calculations provided by Guidehouse suggests that changing the carbon price outside of the model – after the model optimized electric system dispatch at the higher carbon price – would lower the carbon cost of the Electrification scenario by $67 billion.[62] Guidehouse cautions that may not be the correct estimate of the amount by which the Electrification scenario cost would be reduced had a lower carbon price been used because its model could have optimized dispatch of resources differently. That may be true. However, if the model is truly optimizing for cost, further optimization should only make the total cost of the Electrification scenario even less costly. In other words, the $67 billion reduction in cost should be the *minimum* reduction in total cost of high Electrification that would result from use of a lower carbon cost.

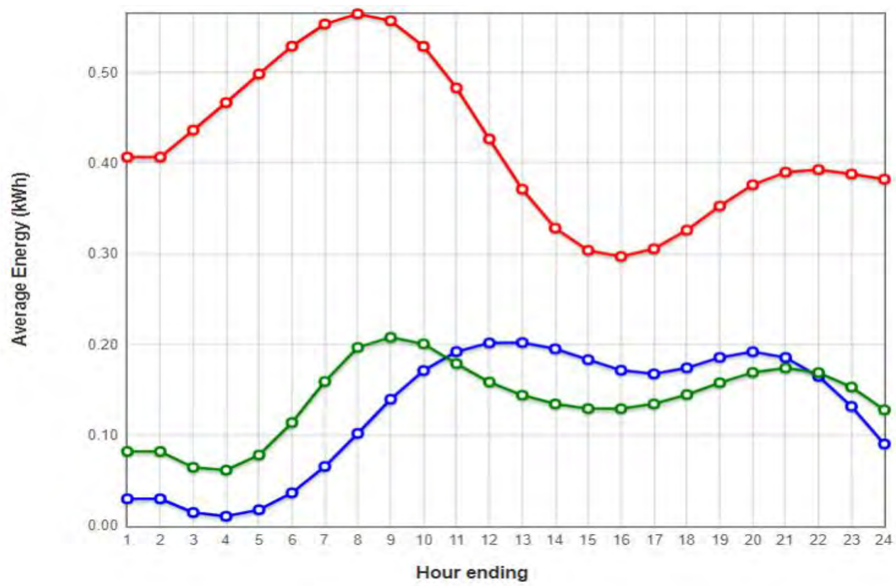
### C. Inappropriate Application of Heating Load Shape to Non-Heating End Uses

In order to estimate the costs to the electric grid of adding new loads from electrification, one must develop assumptions about what seasons of the year and what times of day the electrified loads will add demand to the grid. Those load profiles are commonly referred to as "load shapes". Assumptions about the extent to which electrified loads will add demand during peak hours – typically cold January mornings in Ontario – are particularly important because they drive modeling assumptions about how much new generating capacity (or storage) and related transmission and distribution system capacity needs to be added to the grid.

Guidehouse made the simplifying assumption that all electrified building loads would have the same load shape as electrified heating loads.[63] Put another way, it assumed that the ratio of electricity demand on the winter peak hour to annual electricity consumption would be the same for water heating, drying, cooking and other electrified end uses as for space heating. That assumption is highly inaccurate and problematic. Space heating is a much "peakier" load than other loads that could be electrified. For example, as Figure 4 shows, load shapes developed by the Electric Power Research Institute suggest that residential space heating demand at 8 a.m. on a peak winter day in New York state (the red line) is nearly three times as large as residential water heating demand (green line) and between five and six times as large as clothes drying demand (blue line) per 1000 kWh of annual consumption.[64] Similarly, as Figure 5 shows, commercial space heating demand at 8 a.m. on a winter peak day in New York (blue line) is nearly seven times as large as commercial water heating demand (red line) per 1000 kWh of annual consumption.[65]

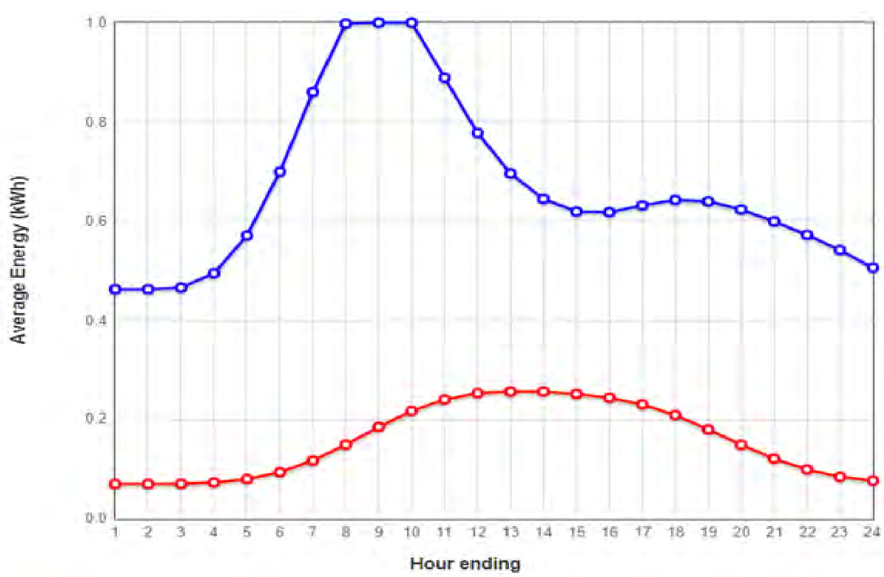
[61] E1/T10/S5 Attachment 2, p. 5 of 88.
[62] JT9.1.
[63] Transcript of Technical Conference March 23, 2023, p. 15, lines 25-27 and p. 16, lines 7-8.
[64] https://loadshape.epri.com/enduse
[65] Ibid.

*Figure 4: Winter Weekday Load Shapes by Residential End Use (per 1000 kWh/year in New York)*




| | Region | Sector/End Use | Season | Day Type |
|---|---|---|---|---|
| (blue) | NYPCC/NY | Res. Clothes Dryer | Off Peak | Peak Weekday |
| (red) | NYPCC/NY | Res. Heating | Off Peak | Peak Weekday |
| (green) | NYPCC/NY | Res. Water Heating | Off Peak | Peak Weekday |

*Figure 5: Winter Weekday Commercial Load Shapes (per 1000 kWh/year for New York)*




| | Region | Sector/End Use | Season | Day Type |
|---|---|---|---|---|
| (blue) | NYPCC/NY | Com. Heating | Off Peak | Peak Weekday |
| (red) | NYPCC/NY | Com. Water Heating | Off Peak | Peak Weekday |

By assuming that all electrified loads have the same load shape as space heating loads, Guidehouse has significantly overstated the amount of new electric generating capacity and transmission capacity that would be needed to serve electrified non-space heating loads. That may not matter much if almost all of the electrified loads – or at least all of the difference in electrified loads between the two scenarios analyzed – were space heating. However, as Table 6 shows, Guidehouse estimates that less than half of the difference in annual electricity sales between the Diversified pathway and the Electrified pathway is attributable to space heating. Thus, the difference in winter morning electric peak demand from buildings in the diversified and electrification scenarios – as well as the difference in related capital investments in electric generating, transmission and distribution capacity in the two scenarios – is probably on the order of 40% less than Guidehouse has estimated.[66]

*Table 6: Guidehouse Estimate of Total and Heating Annual Electricity Consumption by Pathway (TWh)*[67]

| | Diversified | | | Electrification | | | Difference | | |
|---|---|---|---|---|---|---|---|---|---|
| **End Use** | **2030** | **2040** | **2050** | **2030** | **2040** | **2050** | **2030** | **2040** | **2050** |
| Space Heating | 31.3 | 38.8 | 35.1 | 35.2 | 55.0 | 55.9 | 3.9 | 16.2 | 20.8 |
| Total | 118.0 | 134.2 | 141.3 | 125.8 | 172.4 | 187.2 | 7.8 | 38.2 | 45.9 |
| Heat % of Total | | | | | | | 50% | 42% | 45% |

That may help explain why Guidehouse's estimate of electric peak demand under the electrification pathway (82 GW, or about 3.5 times current peak demand) is so much greater than the IESO's estimated peak demand (60 GW or about 2.5 times current peak demand) in its high electrification pathway analysis.[68] It is worth noting that other studies also typically find the increase in electric peak demand by 2050 under high levels of electrification to grow much less than Guidehouse's study has. For example, the E3 New York study found that electric peak demand in 2050 would be about 1.6 times current peak demand under the scenario with the highest levels of electrification.[69]

## D. Outdated and Biased Assumption Regarding Electric Heat Pump Efficiency Degradations

In modeling the impacts of electrifying space heating with air source heat pumps, Guidehouse starts with an assumption about the average annual heating efficiency of a new electric heat pump (e.g., COP of 2.84 for 2023) and then assumes that efficiency degrades by 2% per year through the 18-year life of the unit.[70] The result is that Guidehouse assumes that the average electric heat pump in use in any given year is about 15% less efficient (i.e., requiring 18% more electric energy) than if no such degradation adjustments were made.[71] Guidehouse based its heat pump efficiency degradation assumption on a

[66] If 45% of the difference in annual electricity consumption is space heating and the actual winter peak demand for the other 55% is, on average, only about 25% as great as for space heating, the total peak demand per annual kWh would be about 40% less than if all added electric load was space heating [0.45 + (0.25*0.55) = 0.5875].

[67] Response to ED-47(d) and (e).

[68] IESO, pp. 26-27.

[69] Energy and Environmental Economics (E3), *Appendix G: Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan*, December 2022 (https://climate.ny.gov/resources/scoping-plan/), p. 24 and Technical Supplement Annex 2: Key Drivers Outputs, "Electric Load and Peak by Scenario" tab.

[70] JT1.28 Attachment 3, "HP Turnover" tab, row 140.

[71] These values were derived by changing the efficiency adjustment value to zero in JT1.28 Attachment 3, "HP Turnover" tab, row 140 and seeing how that changed the estimated average stock efficiency values on row 12 of the "Equipment Efficiencies" tab of the same file.

2006 report published by the U.S. Department of Energy's National Renewable Energy Laboratory (NREL).[72]

This assumption is problematic for two reasons. First, the reference is very outdated and not applicable to current advanced heat pump technology. NREL's table with degradation factors for split system heat pumps has separate rows for pre-1981 models, models installed between 1981 and 1991 and models installed after 1991. Also, degradation factors are provided only for single-speed heat pumps, whereas cold climate air source heat pumps (ccASHPs) are typically (if not always) variable speed models. ccASHPs are also fundamentally different in many other ways than heat pumps sold in the 1970s, 1980s and 1990s, including the use of inverter-driven modulating compressors and much more sophisticated controls. Put simply, Guidehouse uses a reference for obsolete equipment without any data or justification for why it would apply to current technology.

Second, Guidehouse does not appear to have made any comparable adjustments to the actual operating efficiencies of gas equipment. The dated NREL report on which Guidehouse relied for electric heat pump efficiency degradation assumptions also includes degradation assumptions for gas furnaces which Guidehouse seems to have ignored. Not surprisingly, the NREL report did not have efficiency degradation assumptions for gas heat pumps, since such products aren't even commercially available today, let alone in 2006 when the report was published. However, there is no basis for assuming that the performance of current generations of cold climate electric climate heat pumps will degrade over time while gas heat pump performance will not.

Put simply, Guidehouse' selective use of an outdated assumption about the degradation of performance of electric air source heat pumps without any degradation factor for gas equipment biases its study against electrification. Eliminating the electric air source heat pump degradation would have the effect of reducing total annual electricity consumption by 1.2 TWh in 2030, 4.8 TWh in 2040 and 5.6 TWh in 2050 in the Electrification scenario and by 0.5 TWh in 2030, 2.2 TWh in 2040 and 2.3 TWh in 2050 in the Diversified scenario.[73] In other words, Guidehouse's inappropriate and selective application of its electric heat pump efficiency degradation assumption has a 0.7 TWh in 2030, 2.6 TWh in 2040 and 3.3 TWh in 2050 bigger impact on the Electrification scenario than on the Diversified scenario.

## E. Dramatically Over-Estimating RNG Availability

Guidehouse has assumed in its decarbonization pathways modeling that the amount of biomethane that is available is equal to the *technical* potential found for Ontario – 224 PJ per year[74] – in the 2020 Torchlight Bioresources study referenced above. As discussed above in a previous section of this report, Torchlight states that it is "unrealistic" for biomethane production to reach anything close to its estimates of technical potential because of "competing uses for feedstock, seasonal feedstock supply risk, logistical constraints including the distance between many feedstocks and the closest natural gas pipeline, precommercial technologies for wood-based production and the high cost of RNG production

[72] https://www.nrel.gov/docs/fy06osti/38238.pdf

[73] These values were derived by eliminating the residential heat pump degradation factor in the "HP_Turnover" tab of JT1.28 Attachment 3, adjusting commercial heat pump efficiency assumptions so that they are equal to residential efficiencies in the "Equip_Efficiencies" tab, and seeing how that changed estimated electricity consumption in the "Summary" tab.

[74] Response to ED-31(a) and Torchlight, p. 52.

from most pathways."[75] Though the study did not estimate feasible potential by province, its estimate of feasible potential for the country was on the order of one-quarter of technical potential (excluding wood-to-gas potential).[76] Thus, Guidehouse has assumed that the amount of biomethane that could displace fossil methane is on the order of four times the amount found by experts in the field to be "feasible".

Enbridge is contending that is a reasonable assumption on the grounds that "over the time horizon of the study (2020 to 2050), policies and regulations will be implemented that support RNG demand creation and that near-term economic, logistical and/or technological challenges associated with realizing RNG supplies are overcome."[77] I disagree. Consider that part of the potential the Torchlight study assumed to actually be "feasible" are resources that would cost in excess of $2.40/m3. Adding significant transportation costs for resources currently deemed too far from the nearest methane pipeline just isn't realistic. It is also not realistic to assume that competing demands for biomethane – potentially including demands for harder to decarbonize sectors of the economy – will just disappear or be outbid by the gas utility. At a minimum, if Guidehouse was going to assume that 100% of technical potential was available, it should have assumed that the cost of acquiring that potential would be much higher than the cost of the feasible potential. As discussed in the next subsection, Guidehouse definitely did not do that.

It is also not realistic to assume that Ontario will achieve significant net out-of-province RNG imports as RNG will be in high demand in many places. Net exports are just as likely. For instance, Vermont Gas is currently planning to acquire RNG from a food processing facility in London, Ontario.[78]

### F. Unrealistically Low Costs Assumed for Biomethane

Guidehouse has effectively assumed a biomethane cost of about $0.86/m3.[79] As discussed in previous sections of my testimony, that is only about one-third of a reasonable cost estimate. Again, in a competitive market, the most expensive unit of production that is purchased will set the market price for all products. A proper analysis would use a supply curve to reflect the fact that biomethane becomes more expensive as the demand increases and as more and more difficult and expensive feedstocks are accessed. As the assumed RNG demand increases, so does the cost.

Guidehouse suggests that it used a lower cost because it analyzed only production costs and not market clearing prices (which would include financing costs, profits and other factors).[80] There are several problems with this response:

- First, an analysis of the societal costs of decarbonization should be based on market prices that will be paid for different decarbonization investments. Societal costs include financing costs and profits. The businesses that produce the products included in the Guidehouse analysis would not exist and would not supply those products if they couldn't finance their production and make a profit on their sale. This is why we use avoided costs – based on market prices for the

[75] Torchlight, p. 54.
[76] Ibid, pp. 54-56.
[77] JT1.15.
[78] https://www.sevendaysvt.com/vermont/hot-air-vermont-gas-says-its-reinventing-itself-to-help-the-climate-critics-call-its-strategy-greenwashing/Content?oid=36110392.
[79] Figure provided by Guidehouse on March 24, 2023.
[80] Response to ED-36.

most expensive unit of energy avoided – when assessing the societal cost-effectiveness of DSM and other programs.

- Second, it is important to note that at least some of the other costs included in Guidehouse's analysis are market clearing prices that include costs of financing and profits. In particular, the costs that Guidehouse assumes for heating equipment and building envelop efficiency measures are based on estimates of actual market prices for such products, including profits earned all along the supply chain (from manufacturer to distributor to contractor to end use customer). In other words, Guidehouse's stated approach is internally inconsistent.
- Third, Guidehouse's decision to focus on "production costs" rather than market clearing prices for gas and electric system supply has the effect of systematically biasing the analysis against electrification and in favor of gaseous fuels, particularly biomethane. Put simply, the supply curve for electricity, for which there is no practical resource limitation, is much flatter than the supply curve for biomethane whose availability is very limited and spread across a much wider range of small sources.

Fourth, Guidehouse based its estimate of the cost of all RNG on a study documenting the cost of RNG from landfills.[81] However, landfills are generally considered the least expensive source of RNG. For example, the 2017 study to develop a marginal GHG emission abatement cost curve that was commissioned by the Ontario Energy Board reported a levelized cost of energy for landfill gas of $0.33 to $0.82 – or a midpoint cost estimate of $0.58 – per m3.[82] The same study reported midpoint cost estimates that were about four times greater for gas from waste water treatment facilities, twice as great for gas from manure, five times greater for gas from source separated organics, and about twice as great for gas from agricultural residues. Maybe more importantly, as shown in Table 7, the 2020 Torchlight study whose estimates of RNG potential Guidehouse relied upon (though it unreasonably focused on technical potential instead of feasible potential) clearly concluded that landfill gas would be much less expensive on average than other sources of RNG. Put simply, it is wrong to base estimates of the cost of all RNG on the least expensive of the many potential sources of RNG – particularly when the study is assuming that the amount of RNG that would be acquired was much greater than what industry experts suggest is the most that is even feasible (including consideration of economics) to acquire.

[81] Technical Conference Day 1 (March 22, 2023), pp. 173.

[82] ICF, Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities (EB-2016-0359), submitted to the Ontario Energy Board, July 20, 2017, pp. 54-55. (https://www.oeb.ca/sites/default/files/OEB_MACC%20Report_20170720.pdf).

*Table 7: Torchlight Study Estimated RNG Production Costs by Feedstock* [83]

| Scenario | Feedstock | Specific CapEx ($ M) | CapEx ($/GJ) | Feedstock ($/GJ) | OpEx ($/GJ) | Total ($/GJ) |
|---|---|---|---|---|---|---|
| SW Ontario Corn | Corn Silage & Chicken Litter | 20 | 21.90 | 7.90 | 11.80 | 41.60 |
| Urban Organics & Manure | SSO & Hog Manure | 35 | 38.30 | -5.00 | 20.60 | 53.90 |
| Prairie Crop Residues | Straw | 27.5 | 30.10 | 8.50 | 16.20 | 54.80 |
| Landfill Gas (best case, upgrader only) | Landfill Gas | 2.5 | 1.85 | 2.15 | 2.1 | 6.10 |
| Landfill Gas (likely) | Landfill Gas | 7.5 | 8.20 | 3.00 | 4.40 | 15.60 |

If the market clearing price for RNG would be set by the most expensive resource in the Torchlight study – Prairie crop residues – the cost of the Diversified scenario would by about $50 billion higher than estimated by Guidehouse and the cost of the Electrification scenario would be about $22 billion higher over the 2030 to 20250 period. In other words, using a more accurate estimate of RNG costs would improve the relative cost of the Electrification scenario by about $28 billion. That is a very conservative estimate of the impact of Guidehouse's biased assumption because it doesn't account for the even more expensive RNG that Guidehouse assumed could become available but that the Torchlight study considered infeasible, in part because of cost.

## G. Unrealistically Low Costs Assumed for Green Hydrogen

Guidehouse appears to have assumed unrealistically low costs for green hydrogen in its analysis. Specifically, it has assumed that hydrogen costs would range from $2.50 to $3.00 per kg in 2030, $1.80 to $2.20 per kg in 2040 and $1.50 to $1.90 per kg in 2050. These ranges cover estimated costs for hydrogen produced in Ontario, Quebec, western Canada, New York, the PJM region and Michigan.[84] By comparison, Enbridge itself recently estimated that costs in Ontario would be $4.37 to $5.46 per kg – about twice the Guidehouse estimate for Ontario in 2030.[85] The Guidehouse estimated costs are also much lower than those estimated by E3 in the recent New York decarbonization study. For example, Guidehouse estimated that green hydrogen produced in New York would cost $2.70/kg in 2030, $1.90/kg in 2040 and $1.70/kg in 2050. E3's estimates for the same state were about 50% higher.[86]

Enbridge and Guidehouse imply that at least part of the reason their cost estimates are lower is that they are estimated costs of production and not retail costs that would include the effects of financing of capital investments, profits or market clearing prices. As discussed in the preceding subsection of this report on the cost of RNG, that is not a reasonable explanation and results in an analysis that is biased in favor of gaseous fuels.

[83] Torchlight, p. 44.
[84] E1/T10/S5 Attachment 2, p. 70 of 88.
[85] JT1.19.
[86] Energy and Environmental Economics (E3), *Appendix G: Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan*, December 2022 (https://climate.ny.gov/resources/scoping-plan/), Annex 1: Input Assumptions, "hydrogen costs" tab. Note: E3 reports costs in US dollars per MMBtu. I converted them to CDN$/kg using the same higher heating value of 141.88 MJ/kg used by Enbridge and a $1.36 exchange rate.

### H. Over-Estimating GHG Emission Reductions from Biomethane

Guidehouse's modeling of net zero emissions pathways assumes that all biomethane has zero GHG emissions, other than emissions that occur as a result of leaks in the Ontario transmission and distribution system. The basis for this assumption is that since biomethane is "biogenic", its emissions should be assumed to be zero. That assumption is flawed and results in an analytical bias against electrification and in favor of biomethane.

First, it is important to acknowledge that burning biomethane produces the same amount of CO2 emissions at the "burner tip" as burning fossil methane. The only reason biomethane may be considered lower GHG-emitting than fossil methane is that its combustion can eliminate other GHG emissions (e.g., methane emissions). In other words, there are some "offsetting" emissions reductions that can be credited to biomethane use. That said, the magnitude of those offsets – or the net lifecycle emissions impacts of biomethane – varies considerably, depending on the source, how it is collected, how it is converted into methane gas, how it is delivered to gas utility pipe, how it is already regulated and other factors. While some sources of biomethane actually have a negative net lifecycle GHG emissions impact, those sources (e.g., dairy farm manure) represent very small portions of the total biomethane resource potential. Most of the bigger sources of biomethane have lifecycle GHG emissions that, though better than fossil gas, are not zero. It is worth noting that the Torchlight study on which Guidehouse relied for its estimates of biomethane potential, uses an average 65% lifecycle GHG emission reduction factor when calculating emissions impacts relative to fossil gas.[87]

Second, to my knowledge, lifecycle emission reduction factors do not yet account for impacts of emissions on the customer's side of the meter. There is a growing body of evidence that suggests a non-trivial portion of methane delivered to home and business appliances is emitted to the atmosphere rather than burned and turned into carbon dioxide.[88] Because methane is a much stronger greenhouse gas than carbon dioxide – with 28-36 times the global warming potential over 100 years and 84-87 times the global warming potential over 20 years[89] – such leaks represent a significant level of GHG emissions that RNG will not and cannot reduce. The GHG emissions resulting from leaks from a home's cook stove will occur in exactly the same magnitude if the fuel being delivered to the home is biomethane as if the fuel delivered to the home was fossil methane.

These realities need to be reflected and accounted for in any analysis of pathways to decarbonizing our buildings. Put simply, Guidehouse's assumption that all RNG is zero-emitting does not address these realities and therefore artificially makes scenarios that rely more heavily on biomethane appear lower cost than the scenario would actually need to be in order to achieve comparable levels of GHG emission reductions as the scenario that relies more heavily on electrification.

### I. Potential Over-Estimation of GHG Emissions Reductions from Blue Hydrogen

Guidehouse has assumed that approximately 4800 PJ (395 billion $m^3$) of blue hydrogen would be consumed between 2030 and 2051 in its Diversified scenario. At that scale of consumption, it is critically important that assumptions about lifecycle emissions from the production, transportation and consumption of the fuel are properly and reasonably estimated. This report does not address the

[87] Torchlight, p. 58.

[88] For example, a recent Stanford study found that "natural gas stoves emit up to 1.3% of the gas they use as unburned methane" (https://news.stanford.edu/2022/01/27/rethinking-cooking-gas/).

[89] https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

reasonableness of Guidehouse's assumptions about blue hydrogen emissions. The issue is instead addressed by Environmental Defence witnesses, Professors Howarth and Jacobson.

### J. Ignoring Potential for Electric Demand Response from Building Loads

Guidehouse's modeling did not include any amount of demand response from the building sector in its modeling of the electric grid impacts of electrification. This is a significant omission that skews the results against electrification.

It is admittedly difficult to precisely estimate the extent to which peak demands from space heating can be shifted to off-peak hours. However, we know that the number is not zero today and is highly likely to improve over time. For example, new electric heat pumps that are coupled with thermal storage that would enable demand response have begun to emerge onto the market.[90] Hydro Quebec and Efficiency Nova Scotia currently offer financial incentives for electric thermal storage.[91] The electric utility industry also has a long history of deploying demand response to reduce water heating contributions to system peak. There are now also a number of electric utility initiatives promoting behind the meter battery storage.[92] The potential for EV batteries with bidirectional chargers to shift peak load is but one example of likely further developments on this front. The bottom line is that assuming zero demand response potential likely biases a decarbonization analysis against electrification.

### K. Overly Optimistic Assumptions about Gas Heat Pumps

Guidehouse assumes that half of all homes that remain gas heating in 2040 would be heated with gas heat pumps. That level of market penetration for a product that isn't even commercially available yet is completely unrealistic.

Guidehouse also assumes that the initial cost of a gas heat pump combined with a new air conditioner was $12,200 in 2020. That cost estimate assumes $8000 for a gas heat pump plus $4200 for an air conditioner.[93] It was based on an "informal survey" by one manufacturer of gas heat pumps.[94] However, that estimate was expressed in 2019 U.S. Dollars. Guidehouse did not convert the estimate to Canadian currency or to 2020 dollars. If it had, the cost would instead be more like $16,500.[95] Correcting that error increases the sum of annual heating equipment costs by about $3 billion under Guidehouse's Electrification Scenario and by about $16 billion under its Diversified Scenario. In other words, it makes the relative economics of the Electrification Scenario look about $13 billion better.

### L. Overly Pessimistic Assumption about Weatherization Savings Life

Guidehouse has assumed that building envelop efficiency improvements save energy for an average of 20 years.[96] That is an unreasonably short period of time. In fact, Enbridge itself currently assumes that

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[90] https://www.harvest-thermal.com/product

[91] See https://www.hydroquebec.com/residential/energy-wise/windows-heating-air-conditioning/thermal-storage/ and https://www.efficiencyns.ca/tools-resources/guide/ets-system-rebate-guide/.

[92] My electric utility, Green Mountain Power, is but one example (https://greenmountainpower.com/rebates-programs/home-energy-storage/).

[93] JT1.28, Attachments 8 and 9, "End-User Costs" tab.

[94] EB-2021-0002, Exh 1.10i.EGI.CCC.40, Attachment 1, p. 31 of 160.

[95] Assuming 1% inflation from 2019 to 2020 (https://www.bls.gov/data/inflation_calculator.htm) and 1.34 USD to CDN exchange rate as of April 14, 2023 (https://www.bankofcanada.ca/rates/exchange/daily-exchange-rates/).

[96] JT1.28, Attachments 8 and 9, "End-User Costs" tab, row 99.

all insulation measures installed through its DSM programs have a life of 30 years.[97] Changing the assumption from 20 years to 30 years has the effect of reducing the sum of annual weatherization costs, net of salvage value in 2050, by $11 billion for the Electrification Scenario and by $5 billion for the Diversified Scenario.[98] In other words, it makes the relative economics of the Electrification Scenario look about $6 billion better.

## M. Unreasonably Pessimistic Assumption about Electric Water Heating Efficiency

As Table 8 shows, Guidehouse assumes that a significant majority of residential gas water heaters that are electrified would be converted to relatively inefficient electric resistance models (Energy Factors of 0.90 to 0.92) rather than to electric heat pump water heaters that typically four times more efficient (Energy Factors of 3.50 to 4.00).[99] Most notably, Guidehouse assumes that by 2040 more than 90% of the gas water heaters that are electrified would be converted to electric resistance models in the Electrification Scenario. While the portion converted to heat pump water heaters increases by 2050, it is still only about one-quarter) of all electrified gas water heaters.

*Table 8: Guidehouse Assumptions Regarding Residential Water Heater Conversions by Scenario and Year*

| | | Electrification Scenario | | | | Diversified Scenario | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Current Type** | **New Type** | **2020** | **2030** | **2040** | **2050** | **2020** | **2030** | **2040** | **2050** |
| Elec Resistance | Elec Heat Pump | 0% | 0% | 30% | 50% | 0% | 0% | 30% | 50% |
| Gas | Elec Resistance | 0% | 4% | 60% | 70% | 0% | 5% | 5% | 25% |
| Gas | Elec Heat Pump | 0% | 4% | 6% | 25% | 0% | 1% | 7% | 10% |
| Gas | Gas Heat Pump | 0% | 1% | 4% | 5% | 0% | 1% | 57% | 65% |

It is also notable that Guidehouse has assumed that a larger proportion of electrified gas water heaters would be heat pump models under the Diversified scenario (over half in 2040) than under the electrification scenario (less than 10% in 2040). In other words, it assumes a much higher portion of gas to electric conversions are efficient in the Diversified scenario than in the Electrification scenario. In addition, Guidehouse has assumed that 30% of homes that currently have electric resistance water heaters would convert to heat pump models by 2040 and 50% by 2050. Why would a much higher percentage of homes with existing electric resistance water heaters be willing to convert to heat pump models than homes with existing gas water heaters?

Put simply, Guidehouse's assumption about the electrification of gas water heaters in the Electrification scenario is incredibly conservative. While the current North American market share for electric heat pump water heaters (as a percent of all electric water heaters sold) may be modest, in at least some jurisdictions in which DSM programs are promoting them, market shares have increased to about 30%.[100] In the context of aggressive climate policies and changes to the technology to make it easier to

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[97] EB-2021-0002 I.9.EGI.GEC.7 Attachment 1.

[98] Estimated by changing the measure life assumption for retrofits in cell I101 of the "End-User Costs" tabs of JT1.28 Attachments 8 and 9. Changes in costs can be found on row 108 of the same tabs.

[99] Guidehouse's assumed efficiencies for heat pump water heaters, starting at an Energy Factor of 3.02 and improving to just 3.18 by 2030, are themselves very conservative. For example, the models typically sold by Home Depot and Lowe's today have Energy Factors between 3.75 and 4.00.

[100] For example, Efficiency Vermont estimates that it is currently achieving about a 30% market share for electric water heater replacements through various efficiency rebate offerings (personal communication with Phil Bickel, Vermont Energy Investment Corporation, 4/18/23).

install, such as development of plug-and-play" 120 volt models,[101] even higher market shares should become possible relatively quickly. In fact, an "advanced water heating initiative" led by several leading energy efficiency organizations with support from the U.S. Department of Energy and the Energy Star program have set a goal of achieving a 100% market share by 2030 for high efficiency, grid-connected heat pump water heaters in residential markets.[102] It is also worth noting that the E3 decarbonization pathways study completed for the Massachusetts' gas utilities assumed that, depending on the scenario, between 64% and 86% of all electric water heaters would be heat pump water heaters by 2050.[103] Guidehouse has suggested that it assumed low market shares for electric heat pump water heaters because of experience with barriers to adoption of the technology to date, including higher first costs and some anecdotal information about some customers not liking them.[104] For reasons just stated, that is not reasonable, particularly when one contrasts that conclusion with Guidehouse's assumption in its Diversified Scenario of massive deployment of gas heat pumps – a technology that also has a high first cost (much higher than that of heat pump water heaters) and that the gas industry has struggled to develop for more than two decades and is still not commercially available for residential applications.

Guidehouse's decision to assume unreasonably high levels of inefficient water heating electrification has a significant impact on its estimates of electricity required to electrify. Specifically, if three-quarters of all residential and commercial electrified gas water heaters adopted heat pump water heaters (and only one-quarter adopted electric resistance water heaters), the total incremental load from building electrification would be about 6.5 TWh per year lower in 2040 and 8.2 TWh lower in 2050 under the Electrification Scenario; it would be about 1.1 TWh lower in 2040 and 3.5 TWh lower in 2050 under the Diversified Scenario.[105] In other words, it would have a much bigger impact on Guidehouse's estimate of the cost of the Electrification Scenario than on its estimate of the cost of the Diversified Scenario.

### N. Excluding Distribution Systems Costs and Customer Fuel Conversion Costs

The Guidehouse study excluded costs associated with creating a distribution system for delivering 100% hydrogen to numerous residential, commercial and industrial customers. It also excluded the cost of converting the methane-carrying pipes and methane-burning appliances in those customers' buildings to pipes that can carry 100% hydrogen and appliances that can burn 100% hydrogen. These are huge omissions.

As discussed in a previous section of this report, it is hard to imagine how the delivery of 100% hydrogen to large numbers of residential and commercial customers could be accomplished without massive investment in a new hydrogen distribution system.

Similarly, significant costs will have to be incurred to enable the substituting of 100% hydrogen for methane in homes and commercial buildings. Methane burning equipment that is also hydrogen-ready will likely be a least a little more expensive than equipment built only to burn methane. Then there will

[101] Gupta, Smita (New Buildings Institute), Scaling Up Market Transformation for Heat Pump Water Heaters, January 19, 2022 (https://newbuildings.org/scaling-up-market-transformation-for-heat-pump-water-heaters/).
[102] Ibid.
[103] E3 and Scottmaden, *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals, Independent Consultant Report, Technical Analysis of Decarbonization Pathways*, March 18, 2022, Appendix 4 (input assumptions), "Scenario parameters (detail)" tab.
[104] Technical Conference Transcript, April 27, 2023, p. 22, line 21 through p. 23, line 19.
[105] Values estimated using JT1.28 Attachment 3.

be significant costs to ensure that all customers downstream of a 100% hydrogen injection point have nothing but hydrogen-ready appliances, plus the cost of physically converting such appliances from methane-burning to hydrogen-burning (as discussed above, hydrogen-ready equipment still requires physical changes to burners, controls, etc.), plus costs to ensure that the pipes and equipment in every single individual home and business can actually safely burn hydrogen (assuming it is even possible without significant new ventilation additions), before hydrogen can start to be delivered instead of methane. Such interventions – potentially a couple of on-site visits for every building switching from methane to 100% hydrogen – will be quite costly and logistically challenging, to say the least.

Guidehouse notes that its analysis also excludes electrification costs associated with upgrading the electric distribution system and upgrading electrical systems in homes and businesses to accommodate larger electric loads. However, those omissions are highly unlikely to be comparable to the costs of creating a new 100% hydrogen delivery system and new hydrogen burning systems in buildings.

While it is true that electric distribution system investments will be necessary to accommodate high levels of electrification, some electrification can occur today without any distribution system upgrades. The same cannot be said of 100% hydrogen delivery to any customer or group of customers. Moreover, electrification can enable some reductions in gas distribution system costs. For example, if new homes and commercial buildings are all-electric, both the costs of connecting them to the gas system and the cost of running gas pipe on the customer side of the meter (i.e., to different appliances in the home or business) are avoided. For that matter, if an existing gas home or commercial building is fully electrified, the need to maintain or replace the gas meter, the need to send gas bills and other gas utility costs of serving those customers are avoided. It is also possible that electrification can eliminate some gas system expansion costs or even allow pruning of parts of the gas system to avoid on-going system maintenance costs. Importantly, there are no electric analogs to these opportunities for gas utility system cost reductions. Because every gas-connected customer is also an electric customer, there are no cost savings to the electric system from continuing to use gas.

Furthermore, while some homes will require electrical panel upgrades in order to electrify space heating, some will not. And for those that do, the costs are generally well-understood and relatively modest.

The bottom line is that omission of both distribution system and customer conversion costs from Guidehouse's study almost certainly biases the results against electrification and in favor of the scenario contemplating mass delivery of 100% hydrogen.

### O. Summary

Overall, Guidehouse's assumptions are highly biased in favor of gas and not credible. There are numerous instances in which optimistic leaps of faith are made about equipment and systems necessary to make continued use of gaseous fuels look economically viable while much more conservative assumptions are made about electric alternatives. For example, Guidehouse assumes high penetrations of residential gas heat pumps and 100% hydrogen furnaces and appliances, despite the fact that these products are not even commercially available today. In contrast, Guidehouse assumes market penetration rates for electric heat pump water heaters in 2040 that are much lower than leading jurisdictions are achieving today through DSM programs. Similarly, Guidehouse assumes that the efficiency of electric heat pumps will degrade 2% per year after installation (based on an outdated study that doesn't apply to current electric heat pump technology) but that gas furnaces and gas heat pumps will experience no such degradation.

To make it easier for the reader to begin to consider numerous concerns about the Guidehouse study in their totality, a summary is provided in Table 9 below. Note that the implications of correcting each Guidehouse error or bias are quantified and monetized where possible. However, that was not possible in many cases without the ability to run Guidehouse's model with changed assumptions. It should also be noted that for the flawed assumptions whose impacts I attempted to quantify, my estimated impacts do not account for interactions with other assumptions. Nor do they account for how changing an assumption might change resource choices that an optimization model might make. Nevertheless, it is abundantly clear that correcting Guidehouse's errors and biases would result in the scenario that places greater emphasis on electrification being not just less costly, but substantially less costly than the scenario that relies more on gaseous fuels including 100% hydrogen. In fact, just correcting the first problematic assumption – the inappropriate use of a higher cost of carbon in the electrification scenario (with resulting higher emission cost even though the scenario produces fewer emissions!) – is enough to make the electrification scenario the lower cost option.

Finally, it is worth noting that the scenarios analyzed by Guidehouse were developed by or with Enbridge. They were not necessarily optimized. And while they were designed to achieve net zero emissions by 2050 – though unlikely to actually do that, at least from a lifecycle emissions basis – they produce much lower emissions reductions from the buildings sectors by 2030 (9% in the Diversified Scenario and 13% in the Electrification Scenario relative to 2020) than the projections set out in Canada's 2030 Emissions Reduction Plan and its Green Building Strategy.

*Table 9: Summary of Concerns with Guidehouse's P2NZ Study*

| Assumption | Concern | Implications |
|---|---|---|
| Cost of CO2e Emissions | Guidehouse improperly treats carbon taxes as a societal cost and assumes a much higher cost of emissions for electrification scenario. | Using same cost of emissions reduces electrification scenario costs by ~$67+ billion. That's more than enough (without any other changes) to make it the lower cost option. |
| Load Shapes for Electrified End Uses | Guidehouse assumes all building end uses - including water heating, cooking and drying - have the same seasonal and hourly load profiles as space heating. | Winter morning peak demand from electrified building loads likely to be about 40% lower than estimated by Guidehouse. |
| Heating Equipment Efficiency Degradation after Install | Guidehouse assumes electric heat pump efficiency degrades 2%/year after installation based on reference for very different older generations of heat pumps. No degradation of gas furnace or gas heat pump efficiency assumed, despite the same report suggesting gas furnace efficiency also degrades . | Guidehouse estimates of added electricity consumption for ASHP space heating overstated by 18%. The adverse effect is 0.7 TWh in 2030, 2.6 TWh in 2040 and 3.3 TWh in 2050 more in the Electrified scenario than in the Diversified scenario. |
| RNG Availability | Guidehouse assumes that the entire "technical potential" for RNG in Ontario would be available, even though the expert report it references suggests it would be feasible to access less than one-quarter of that amount. | Substantially more expensive gaseous resources would have had to be deployed under the "Diversified Scenario" if RNG supply constraints were reasonably set, possibly making the Diversified scenario inconsistent with a net zero emissions objective. |
| RNG Costs | Guidehouse RNG cost is for landfill gas, but most of the RNG potential it assumed to be available is from other much more expensive sources. The most expensive source of RNG would set the market clearing price for all RNG. | RNG costs likely to be at least 3 times greater than assumed, improving the relative cost of Electrification Scenario by at least $28 billion. The difference could be much higher because Guidehouse assumes RNG potential four times what its own reference study says is feasible, which would require accessing even more expensive RNG |
| GHG Emission Reductions from RNG | Guidehouse's analysis does not address the full lifecycle emissions of biomethane. Thus, it overstates the amount of emission reductions RNG provides. | If lifecycle emissions were fully addressed, additional emission reduction measures would have to be deployed to achieve net zero emissions, adding significant cost, especially for the Diversified Scenario, potentially making it inconsistent with net zero emissions objective. |
| GHG Emission Reductions from Blue H2 | See evidence of Professors Howarth and Jacobson | If blue hydrogen emissions are greater than assumed, it would make the Diversified scenario more expensive and/or inconsistent with net zero emissions objective. |
| Electric Demand Response Resources | Guidehouse did not consider or model the potential for demand response to be applied to newly electrified space heating and water heating loads. | Electric system capacity costs from electrification are overstated, but difficult to quantify the magnitude of the overstatement. |
| Gas Heat Pump Costs | Guidehouse used an informal estimate from a gas heat pump manufacturer rather than a much higher recent Enbridge estimate. Worse, it failed to recognize that the estimate it used was expressed in U.S. rather than Canadian dollars. | Converting to Canadian dollars results in an increase cost of $3 billion for the Electrification Scenario and $16 billion for the Diversified Scenario - improving the relative cost of the Electrification Scenario by $13 billion. |
| Home Weatherization Savings Life | Guidehouse conservatively assumed that insulation and other building envelop efficiency improvements would last only 20 years. Enbridge assumes a more reasonable 30 years in its DSM planning. | Using a 30 year life reduces the cost of the Electrification Scenario by $11 billion and the Diversified Scenario by $5 billion - improving the relative cost of the Electrification Scenario by $6 billion. |
| Electric Water Heating Efficiency | Guidehouse assumes only ~10% of gas to electric water heating conversions by 2040 and ~25% by 2050 are to efficient heat pump water heaters. Leading jurisdictions are already achieving market penetration rates higher than that. Other studies assume much higher heat pump water heating rates. | If 75% of all such conversions were to heat pump water heaters, total forecast electric demand would be about 8.2 TWh (about 2%) lower under the Electrification Scenario (and about 3.5 TWh lower under the Diversified Scenario. |
| Customer Conversion Costs | Guidehouse did not address customer conversion costs - other than costs of heating equipment. Behind-the-meter pipe retrofits, ventilation requirements and utility inspection costs could be substantial. | Likely bias against electrification because costs likely to be higher for conversion to 100% hydrogen than for electrification for residential and commercial customers. |
| Utility Distribution System Costs | Guidehoulse excluded the cost of converting the distribuiton system to 100% hydrogen and all other incremental gas and electric distribution system costs. | Likely bias against electrification becuase the costs for 100% hydrogen delivery to residential and commercial customers likely to be much higher than for electrification of those customers. Also, electrification will enable reductions in gas utility costs from fewer customers (e.g., fewer connections, meters, customer service reps, etc.) as well capital and O&M cost savings from pruning parts of the gas distribution system . |

# IV. Protecting Consumers in the Context of Future Decarbonization

While there is always uncertainty about how the future will unfold, it is very likely that decarbonization of the economy (i.e., achieving net zero GHG emissions by 2050) will ultimately mean very high levels of electrification of buildings and, to a somewhat lesser extent, electrification of industrial operations.[106] The uncertainty is when the gas system will begin to shrink, how fast the shrinking will accelerate, and exactly how much smaller the gas system will ultimately become. This reality has major implications for gas distribution system investments that regulatory policy and decisions should address and reflect in order to protect consumers. What follows are discussions of several ways in which the Board should consider addressing and reflecting the likely implications of decarbonization.

## 1. Modify Policy on New Connections to Reduce Risk of Stranded Assets

Regulatory policy on new connections should be reconsidered in light of the likelihood of extensive electrification and the significant savings customers can achieve by switching from gas to electric heating. The costs of new connections are largely socialized in rates, to be repaid over long periods (40 years) through forecast distribution rate revenue from the newly connected customers. This creates a major risk for existing customers. If new customers convert to all-electric buildings 10 or 15 years from now, the capital cost of having connected them to the Enbridge system will not have been fully recovered under current connection rules, creating a stranded asset that customers still on the gas system will have to pay. The same is true of existing homes or businesses that consider connecting to the gas system today.

In addition, modifying policy on new connections could cause an immediate reduction in rates by reducing gas connection infrastructure costs and/or reducing the portion of those costs borne by existing ratepayers.

The cost of new connections in the context of decarbonization also creates the risk of unfair cost allocation. Even if a new customer remains on the system long enough to pay for the costs to connect them to the system, they would still not have contributed at all to the cost of the remaining system. It is unclear how long they would need to remain with the system in order to pay a fair share of the costs of the gas system, but merely remaining long enough to pay their own connection costs is clearly insufficient.

Also, if most new homes and businesses are ultimately going to have to become all-electric – and/or going to want to become all-electric because of significant cost advantages relative to very expensive biomethane and/or hydrogen – it is much easier and less costly to design and build those homes and businesses as all-electric buildings from the get-go. If they are instead built to burn methane, the task of decarbonizing Enbridge's system will get harder and more expensive because of the additional emission reductions required – with all gas customers collectively absorbing that added cost.

Thus, the Board should consider several policies for both mitigating the risk of stranded or underutilized assets from new connections and leveling the playing field between gas and electricity.

[106] Moreover, even if Enbridge's much less likely vision of the future were to become reality, there would still be considerable electrification, reductions in annual gas throughput and reductions in gas peak demands.

## A. Shorten New Construction Connection Cost Recovery Periods

The Board direct Enbridge to shorten new construction connection cost recovery periods. Enbridge is proposing to maintain most of its existing policies with respect to recovering costs associated with connection of new small volume customer buildings – e.g., new residential subdivisions and new small commercial developments. In particular, it is not proposing any changes to the following existing policies:

- **Customer connection horizon of 10 years**. This is the period of time within which a new building must be connected to the gas system in order to be subject to an agreement on any terms regarding costs of connections, including contributions in aid of construction, system expansion surcharges or temporary connection surcharges.
- **Customer revenue horizon of 40 years**. This is the period of time over which additional revenue collected from new connections must be sufficient to cover connection costs minus any initial contributions or surcharges. Note that the comparable horizon for electric connections in Ontario is 25 years.[107]

These policies have been in place since the Board's decision in 1998 in the EBO 188 case. However, our understanding about the future use of the gas distribution system is very different today than it was 25 years ago. As discussed in this report, it is highly likely that many if not the vast majority of existing residential and commercial gas customers will have to electrify in the next couple of decades for the Ontario economy to fully decarbonize. Even in Enbridge's preferred "diversified scenario" from the Guidehouse P2NZ study, 36.5% of existing residential gas customers are assumed to have converted to electric heat pumps by 2040.[108]

In that context, the case for greater certainty about revenue recovery from any new connections – to guard against the risk of stranded assets – is very compelling. Since the typical life of a new gas furnace is estimated to be 18 years, and it is most likely that a customer will electrify at the time that they need to replace their heating system, a maximum customer revenue horizon of 15 years would be much more appropriate. That said, some customers will electrify sooner, such as when they replace a central air conditioner and/or in an effort to save energy costs or to decarbonize.

Given the uncertainty about the pace of decarbonization and its impact on the gas system, it would also make sense to tighten up the maximum customer connection horizon. A reduction from 10 years to the 5 years used on the electricity system is reasonable.

It is worth noting that Enbridge has estimated that reducing the maximum customer revenue horizon to 15 years would reduce system access spending by about $600 million over the 2024-2028 period.[109]

## B. Reduce Infill Connection Costs Funded by Rates

A similar change is warranted for infill connections. The portion of the infill connection costs covered by rates should be limited to those costs that would be recouped over 15 years. In contrast, Enbridge's proposed harmonized connection policy would fund the majority of infill connection costs from rates (e.g. the meter and up to 20 meters of service line) even though this cost would not be recovered from

[107] www.oeb.ca/oeb/_Documents/Regulatory/Distribution_System_Code_AppB.pdf
[108] JT1.28, Attachment 3, "DivScen_Assumptions" tab, rows 23-24.
[109] JT5.21, p. 3.

those customers' distribution charges until after 2050.[110] If the new customer converts to all-electric buildings 10 or 15 years from now, the capital cost of having connected them to the Enbridge system will not have been fully recovered under current connection rules, creating a stranded asset that customers still on the gas system will have to pay. Even if they stay just long enough to pay off their individual connection costs, they would have had a "free ride" by not contributing any costs to the overall system beyond their own service line and meter.

### C. Require All New Connections to Be Net-Zero GHG

From a public policy perspective, there are compelling arguments for a moratorium on new gas connections. Indeed, the state of New York just enacted legislation that would ban the use of fossil gas and other fossil fuels in most new buildings.[111] An alternative to a new connections moratorium would be to require that (1) all new gas connections be heated with hybrid systems comprised of cold climate electric heat pumps with gas furnaces used only for back-up heat on the coldest hours and days of the year; and (2) all of the gas supplied on those coldest hours and days of the year will be net-zero GHG-emitting with the new customers bearing the full cost of that more expensive gas (i.e., without cross-subsidies from existing gas customers).

Energir, the Quebec gas utility, recently announced that it will seek approval in its next rate case for a similar, though less restrictive policy. It would give potential new customers the option of either a 70% electric / 30% RNG option or a 100% RNG option.[112] Given the significant limitations on RNG availability, it would be more prudent to limit this offer, at least for residential and commercial buildings, to cold climate electric heat pump-gas furnace systems in which the electric heat pump delivers much more than 70% of heating needs – probably 90% or more – in most of Ontario.

## 2. Align Depreciation and Rate Design with Expectation of Declining Gas Throughput

The proposed approach to depreciation is highly problematic because it does not address decarbonization risks at all and implicitly assumes a 0% risk of underutilized or stranded assets even long past 2050. Given the almost certain inter-generational inequities that will arise from decarbonization of the gas system in Ontario under the Company's current or proposed approach to asset depreciation, the Board should consider and implement alternative approaches. Specifically, the Board should require Enbridge to assess near-term and longer-term rates, costs of capital and inter-generational equity impacts of (1) maintaining its currently proposed Equal Life Group (ELG) depreciation method, (2) adopting an Economic Planning Horizon (EPH) for new assets, (3) adopting an EPH for all assets, and (4) switching to a Units of Production (UOP) method of asset depreciation. That analysis should be performed using load forecasts consistent with the most likely decarbonization pathway or pathways.

The Board should require that Enbridge file this analysis in 2024. It is important that this happen as soon as it reasonably can. The longer we wait, the closer we get to the point when gas sales are likely to decline, reducing the ability to mitigate against inter-generational inequities. Also, the longer we wait, the greater the short-term adverse effect on customers still on the system. For example, Enbridge estimates that adopting a 2050 EPH in 2024 would increase the amount of revenue required to be collected from ratepayers in that year by $257 million, but waiting to adopt a 2050 EPH until 2028 will

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[110] JT3.11.

[111] https://www.washingtonpost.com/climate-environment/2023/05/03/newyork-gas-ban-climate-change/.

[112] https://www.energir.com/en/about/media/news/vers-la-carboneutralite-des-batiments/

result in an increase of $342 million and waiting until 2030 will result in an increase of $405.[113] In other words, there is an opportunity cost to waiting to make changes to depreciation approaches.

As the earlier sections of this report make clear, much of the existing Enbridge Gas distribution system – particularly the parts of the system predominantly serving residential and commercial buildings – will be used much less in a decarbonized future than they are today. For example, as shown in Table 1 (section II((2)(F) above), decarbonization studies generally suggest annual gas sales to residential, commercial, and industrial customers will decline by 70-90% or more by 2050. Even the fundamentally flawed and biased study conducted by Guidehouse for Enbridge suggests that gas sales to residential and commercial customers will decline dramatically by 2050.[114]

Put simply, decarbonization is likely going to result in far fewer gas customers paying for undepreciated gas asset costs than are paying for them today, with the cost of those assets being recovered over a much smaller volume of gas sales than is the case today. At best, this raises a serious concern about inter-generational equity. It could lead to what is sometimes called a “death spiral” in which increasing electrification leading to higher gas rates drives even more customers to electrify with only those customers least able to afford to leave the system left paying for it. That kind of feedback loop and its effects on levels of electrification is typically not accounted for in decarbonization studies.

In its filing, Enbridge has proposed a shift from an “Average Life Group” (ALG) approach for depreciating gas assets to an “Equal Life Group” (ELG) approach. Enbridge’s consultant, Concentric Energy Advisors, explains that the new ELG approach will create greater inter-generational equity than the current Enbridge ALG approach by better aligning the timing of asset cost recovery with the mix of different expected lives of the different assets within an asset group.[115] That is a good thing. However, it is important to recognize that the ELG approach only addresses one form of inter-generational inequity – accounting for the fact that some types of equipment have shorter lives than the average life of all equipment with which they are grouped. It does not address inter-generational inequities associated with the likely decline in the level of use of assets in the future relative to today.[116]

Enbridge states that it considered the potential for introduction of an “Economic Planning Horizon” (EPH) which would require that recovery of all past and new capital investments be achieved by a fixed date – e.g., 2050 – in order to account for the impact that the energy transition would have on the economic life of Enbridge’s assets. The Company concluded that an EPH “is not appropriate at this time” because of the possibility that low carbon fuels such as biomethane and hydrogen would be “viable sustainable alternatives” to fossil gas. Enbridge pointed to the Guidehouse P2NZ study as evidence that its gas system “will be a key contributor to achieving net-zero in the province.”[117] Those statements

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[113] JT4.17.
[114] Under its Electrification Scenario, Guidehouse estimates total annual gas sales to residential and commercial customers to be nearly 90% less than in 2020; even under its Diversified Scenario, total annual gas sales to residential and commercial buildings are estimated by be about half as large as in 2020. (E1/T10/S5/Attachment 2, p. 29 of 86) Moreover, much of the remaining gas throughput will be hydrogen, most if not all of which will have to be delivered through new dedicated hydrogen distribution pipes rather than existing methane distribution pipes.
[115] E4/T5/S1 Attachment 1, p. 15 of 451.
[116] In response to a question from GEC attorney David Poch, Larry Kennedy of Concentric Energy Advisors confirmed that their current study did not adjust ELG for the impacts of future declines in gas throughput. Transcript of Technical Conference, March 27, 2023, p. 127, lines 7-19.
[117] E1/T10/S4 p. 18 or 20.

ignore the reality that even the gas utility's most optimistic view of the future will involve significant loss of customers and gas energy sales. They also do not account for the fundamental flaws in the Guidehouse report, discussed above.

Enbridge's consultant, Concentric Energy Advisors, also addressed the potential application of an EPH. Concentric observed that "while there is strong evidence that the future of natural gas in Ontario may be impacted by climate change legislation, it is still unknown to what extent this change will impact EGI's system." Concentric concluded that additional study of the changes that climate policy will have on Enbridge should be undertaken before adopting an EPH.[118] This response is less than satisfying. While it is certainly true that there is some uncertainty about the future impacts of the energy transition on the gas utility, the uncertainty is more about the magnitude and precise timing of the decline in use of the system, not whether there will be a decline. Furthermore, an EPH can be adjusted over time.

Concentric acknowledges that "intergenerational equity would require that the original cost of investment of an asset is recovered by the customers who gain the benefit of the assets." However, it suggests that an EPH is not the appropriate mechanism to address intergenerational inequities resulting from a substantial reduction in customer load because some customers will still be using the assets after the EPH cut-off date.[119] Concentric is suggesting that if gas assets will not be retired, there would be an inter-generational inequity associated with the fact that the much smaller number of customers still using the gas system after 2050 would benefit – at the expense of current customers and those still on the system through 2050 – if an 2050 EPH were adopted. However, Concentric never addresses why that inequity should rule out adoption of an EPH while the inequity associated with future customers paying much more for an asset per unit of gas energy consumption does not rule out use of a ELG approach to depreciation that does not account for such reductions in energy throughput. Surely it is possible that the inequity of post-2050 customers getting a "free ride" would be outweighed by the increase in equity resulting from assigning a larger portion of the costs of gas assets to the 2020s and even the 2030s when many more customers are using the system. Note that New York regulators recently required gas utilities in that state to file depreciation studies that examine several scenarios, including one in which all new gas assets are fully depreciated by 2050 and another in which all gas assets are fully depreciated by 2050. These studies are intended to "inform future discussions of how best to recover costs of assets and reduce potential stranded costs in the LDC's respective rate proceedings."[120]

Concentric did suggest a potential alternative to EPH as a way to address inter-generational inequities caused by gas customers exiting the system and gas sales declining over time: a "units of production" (UOP) depreciation method.[121] Under a UOP, annual depreciation expense is proportional to expected usage in a given year relative to total expected lifetime usage. As explained during the Technical Conference, this method may offer greater flexibility to periodically adjust for evolving expectations

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[118] E4/T5/S1, Attachment 1, p. 19 of 451.
[119] Response to GEC-66c.
[120] State of New York Public Service Commission, Order Adopting Gas System Planning Process, Case 20-G-0131 and Case 20-G-0297, May 12, 2022, pp. 61-62.
[121] Response to GEC-66d.

about changes in use of the gas system.[122] The challenge would be in reaching agreement on estimates of expected long-term changes in gas consumption.

UOP depreciation is beginning to be considered in some other jurisdictions. For example, Pacific Gas and Electric (PG&E), a very large dual-fuel utility in California, proposed in its 2023 general rate case application that its regulators approve a proposal "to use the units of production method of cost recovery for depreciation of PG&E's gas distribution facilities due to the anticipated reduction in throughput as the state reduces its reliance on natural gas as a fuel."[123] Similarly, the Massachusetts gas utilities recently provided the following recommendation to their regulators:

> *The Department should investigate the role of accelerated depreciation to align cost recovery of gas distribution costs with the utilization of the distribution system rather than the useful life of the assets that make up the distribution system. The Consultants offered an example, known as Units of Production ("UOP") depreciation method. The UOP method is recognized by the National Association of Regulatory Utility Commissioners. The LDCs encourage the Department to investigate this cost recovery option in order to mitigate customer affordability and equity concerns to the extent that gas customers decrease over time as the LDCs pursue decarbonization and electrification strategies.*[124]

Regardless of the specific approach taken, it is important that steps be taken as soon as possible to align depreciation approaches with the likely declines in gas throughput to ensure equity and ongoing affordability.

### 3. Require Assessment of Repair vs. Replace Trade-offs for Aging Pipe

One important way to reduce the risk of stranded or under-utilized gas system assets, and related long-term adverse gas rate impacts, is to reduce the magnitude of new investment in such assets – whenever that can be done safely, without significant risk of system reliability problems and at reasonable cost. Put simply, there is an economic value to "buying time" by deferring capital investments in gas distribution system infrastructure when there is a known and substantial risk that those assets could become stranded or under-utilized. That value should be reflected in regulatory decisions on such investments.

To that end, the Board should require Enbridge to explicitly assess the potential for repairing (whenever that is feasible) rather than replacing aging pipes – and to conduct that assessment in a way that accounts for the possibility that a new pipe will be underutilized or stranded before the end of its life. Such assessments should include estimates of any potential near-term cost savings and related differences in rate impacts, any potential differences in long-term costs and rate impacts, the magnitude of any differences in methane leaks, the nature of any differences in safety risks, differences between how long repairs would last relative to life of a new pipe, the long-term potential to prune the gas system so that the pipe is no longer needed in the context of future decarbonization pathways, and other relevant factors. That kind of analysis would enable the utility, stakeholders and the Board to

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[122] Technical Conference, March 27, 2023, p. 128 line 26 through p. 129 line 6.
[123] PG&E, 2023 General Rate Case Application, June 30, 2021, p. 10.
[124] Massachusetts Gas LDCs, Common Regulatory Framework and Overview of Net Zero Enablement Plans, regulatory proceeding D.P.U. 20-80, p. 21 (https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14633273).

routinely assess cost, stranded/under-utilized asset risk, and other trade-offs of a repair vs. replace decision. For example, it may be reasonable to accept a shorter-term fix with lower cost for 10-15 years (and perhaps even again in another 10-15 years) if there is any chance of eliminating the need for the pipe replacement by pruning the gas system over the next couple of decades.[125]

### 4. Improve IRP to Reduce Risk of Stranded/Under-Utilized Assets

A second important category of capital investments is upgrading the capacity of pipes to ensure reliability can be maintained for growing methane peak demands. Two years ago, the Board issued an order on Gas Integrated Resource Planning (IRP). However, our collective understanding of the potential implications of the energy transition has evolved significantly since evidence was presented in that case. Thus, at least two modifications to the policy the Board put forward in that case should be considered in this proceeding.

#### A. Removing Prohibition on Electrification Measures as IRPAs

The Board should remove the current restriction on considering electrification measures as potential IRPAs. IRPAs are the term used in the OEB policy for non-pipeline alternatives to distribution needs. Gas utilities in other jurisdictions have begun to assess and even propose IRPAs that include electrification in order to cost-effectively avoid expensive gas distribution system upgrades. Concern about the risk of stranded gas assets, given the likely shrinking of the gas system as economies decarbonize, has been an important part of the context for those developments. For example, last year Pacific Gas and Electric Company (PG&E) proposed a pilot project in which it would retire a natural gas pipeline by electrifying 1200 housing units on the California State University Monterey Bay campus. As the Sustainability Director for the University stated "As California shifts to electrification, any new investments in natural gas infrastructure risks becoming a stranded asset. It is like buying a fax machine in 1999."[126] "PG&E estimates that the cost to gas customers to complete this alternative zonal electrification work will be less than the cost to replace the gas system."[127] Further, "the net present value of cash costs of electrification for…the Project have a value of $14.4 million, and the value of the benefits of the Project (i.e. avoided costs of conventional gas pipe replacement) are approximately $15.4 million, resulting in a net benefit of approximately $1.0 million to customers."[128] A regulatory decision on the case is still pending.

#### B. Require Analysis of IRPAs Under Multiple Possible Future Load Forecasts

Load forecasts drive determinations of needs to upgrade gas transmission and/or distribution system capacities, the timing of those needs, the extent to which deployment of IRPAs could defer such needs, and therefore the relative cost-effectiveness of traditional supply and IRPA solutions to addressing the need. To date, the load forecasts that Enbridge has used to assess needs have not reflected the potential for peak demands to begin to decline in the future as climate policy and related market trends accelerate electrification. To be fair, Enbridge needs to ensure that its customers' peak hour energy needs are met, so it cannot rely on uncertain estimates of when gas demand will begin to decline in

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[125] Note that the pruning of the methane delivery system could be enabled either by electrification of a neighborhood or community and/or by bringing new 100% hydrogen pipe to the area.

[126] https://csumb.edu/news/news-listing/east-campus-may-become-californias-largest-electrification-project/

[127] Ward, A. & Pendelton, J. (August 10, 2022). Application of Pacific Gas and Electric Company (U 39 G) for Approval of Zonal Electrification Pilot Project and Request for Expedited Schedule. Filed before the Public Utilities Commission of the State of California. P. 1.

[128] Ibid. P. 4.

identifying potential capacity needs that must be addressed. However, it can and should consider those uncertain futures when assessing the relative merits of different approaches – both traditional supply investments and IRPAs – to meeting those potential needs. The Board should require them to begin to do so. More specifically, the Board should require that Enbridge examine the need for capacity upgrades and assess the relative cost-effectiveness of IRPAs – both rate impacts akin to Phase 1 of the recently approved IRPA cost-effectiveness framework and customer and societal impacts akin to Phases 2 and 3 of the framework[129] – under both Enbridge's traditional load forecast and under a forecast (or two) of accelerating electrification consistent with decarbonization pathways studies. A conceptual illustration of how such scenario analyses could framed is presented in Appendix B to this report.

### 5. Segregated Fund for Site Restoration

There are compelling arguments for site restoration funds to be moved to a protected and segregated fund as the need for a future gas pipeline system is increasingly in question. The obvious rationale is to protect future customers and taxpayers from this future liability, including in a "death spiral" scenario (discussed above). The risk is material and the potential magnitude of the risk is in the billions of dollars. However, I have not attempted to determine the net financial impact on customers. I recommend that the issue be addressed in the next phase of this proceeding based on a deeper analysis by a third party that would provide a full and balanced examination of the cost impacts and recommendations on the design and implementation of a segregated fund that would maximize returns on funds held for site restoration costs, minimize administration costs, and minimize liability for customers.

### 6. Reduce Capital Spending Where Possible

The risk of underutilized and stranded assets calls for additional efforts to reduce capital spending, wherever that is possible, especially on long-lived infrastructure. A number of my recommendations will achieve that end, but could be others. Utilities and regulators always should seek to avoid unnecessary capital spending, but even greater scrutiny is required in the current context.

## V. Conclusion

Major declines in peak and annual gas demand are very likely in the future as efforts to decarbonize the Ontario economy accelerate. This is the conclusion of most independent decarbonization pathways studies. It is also consistent with an analysis of the availability and feasibility of the electric and gas technologies required for net zero greenhouse gas (GHG) emissions and the current cost effectiveness of electrification. It is even consistent with results of Enbridge's own decarbonization study if just one of the most glaring of the many flaws in the study is corrected.

The potential implications of declining gas peak demand and gas sales are significant and important. In a nutshell, there is a growing risk that current and any new gas capital assets will become underutilized, if not stranded. This creates significant risks for the ratepayers who would be saddled with paying for those assets in the future. It will likely also create significant inequities between customers today and those left on the system in the future.

To mitigate these risks, we recommend that Enbridge and/or the OEB take the steps in section IV of this report above.

[129] Including changes to Phases 1, 2 and 3 of cost-effectiveness framework proposed by Gas IRP Working Group.

# Appendix A: Assumptions for Customer Economics of Electrification

*Table 10: Equipment Cost, Efficiency and Energy Consumption Assumptions*

| | 2023 Initial Capital Cost | Life | Level-ized Annual Cost | 2023 Avg Heating COP | 2030 Avg Heating COP | Avg Cooling SEER | Other COPs | Annual Gas $m^3$ | Annual Electric kWh | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Heating | Cooling | Other | Total |
| **Heating/Cooling** | | | | | | | | | | | | |
| Current Avg Furnace + Central A/C | | | | 0.90 | | 13 | | 2117 | 631 | 779 | | 1,410 |
| New Gas Furnace + Central A/C | $8,000 | 18 | $632 | 0.95 | 0.95 | 14 | | 2006 | 631 | 723 | | 1,354 |
| cold climate ASHP | $4,600 | 18 | $363 | 2.84 | 2.93 | 18 | | | 7,279 | 563 | | 7,842 |
| **Water Heating** | | | | | | | | | | | | |
| Current Stock Avg gas water heater | | | | | | | 0.63 | 441 | | | | - |
| Gas Water Heater | $3,016 | 14.5 | $278 | | | | 0.83 | 335 | | | | - |
| Heat Pump Water Heater | $1,111 | 15.1 | $99 | | | | 3.73 | | 808 | | | 808 |
| **Drying** | | | | | | | | | | | | |
| Gas Dryer | $1,223 | 13 | $123 | | | | 3.48 | 53 | | | 108 | 108 |
| Electric Dryer | $998 | 13 | $100 | | | | 3.93 | | | | 608 | 608 |
| **Cooking** | | | | | | | | | | | | |
| Gas Range | $1,195 | 15 | $107 | | | | | 94 | | | | - |
| Electric Range | $1,476 | 17 | $121 | | | | | | | | 290 | 290 |

*Table 11: Current Residential Energy Price Assumptions (2023 $)*

| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas** | | | | | | | | | | | | | | | | | | |
| Fixed Annual Charges | $310 | $310 | $310 | $310 | $310 | $310 | $310 | $310 | $310 | $310 | $310 | $310 | $310 | $310 | $310 | $310 | $310 | $310 |
| Variable Charges | | | | | | | | | | | | | | | | | | |
| Commodity | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 | $0.221 |
| Transportation | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 | $0.050 |
| Distribution | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 | $0.118 |
| Carbon Tax | $0.126 | $0.152 | $0.176 | $0.200 | $0.223 | $0.245 | $0.266 | $0.286 | $0.286 | $0.286 | $0.286 | $0.286 | $0.286 | $0.286 | $0.286 | $0.286 | $0.286 | $0.286 |
| HST | $0.067 | $0.070 | $0.074 | $0.077 | $0.080 | $0.082 | $0.085 | $0.088 | $0.088 | $0.088 | $0.088 | $0.088 | $0.088 | $0.088 | $0.088 | $0.088 | $0.088 | $0.088 |
| Total | $0.582 | $0.611 | $0.639 | $0.666 | $0.692 | $0.717 | $0.741 | $0.763 | $0.763 | $0.763 | $0.763 | $0.763 | $0.763 | $0.763 | $0.763 | $0.763 | $0.763 | $0.763 |
| **Electric** | | | | | | | | | | | | | | | | | | |
| Fixed Annual Charges | $561 | $561 | $561 | $561 | $561 | $561 | $561 | $561 | $561 | $561 | $561 | $561 | $561 | $561 | $561 | $561 | $561 | $561 |
| Variable Charges | | | | | | | | | | | | | | | | | | |
| Commodity | $0.093 | | | | | | | | | | | | | | | | | |
| Transmission | $0.019 | | | | | | | | | | | | | | | | | |
| Wholesale Mkt Serv | $0.005 | | | | | | | | | | | | | | | | | |
| Riders | $0.001 | | | | | | | | | | | | | | | | | |
| HST | $0.015 | | | | | | | | | | | | | | | | | |
| Total | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 | $0.133 |

## Appendix B: Hypothetical Example of IRP Scenario Analysis

In many respects, the most important aspect of risk for gas infrastructure investments today is the potential for climate policy to (1) render such investments unnecessary, at least in the medium to long run, if gas demands are going to decline because of either increased electrification and/or much higher gas prices associated with renewable gas; and (2) add value to efficiency resources and electrification because of both avoided future carbon emission compliance costs (beyond those currently reflected in carbon taxes) and/or higher avoided costs of gas associated with low-GHG gases. Conceptually, one can conceive of three potential futures related to climate policy:

1. Canada does not follow through on its commitment to achieve net zero greenhouse gas emissions, or at least lowers its ambition and imposes no new requirements on fossil gas;
2. Canada follows through on its net zero emission commitments, adopts additional policies requiring increasingly stringent reductions in the consumption of fossil gas, and those requirements are met with a combination of electrification and low-GHG gases; and
3. Canada follows through on its net zero emission commitments, adopts additional policies requiring increasingly stringent reductions in the consumption of fossil gas, and those requirements are met largely with electrification of gas end uses.

Enbridge could be required to estimate how the need for an infrastructure capacity upgrade would be affected under each of these scenarios, how gas prices would likely change under each of them, and how the resulting net present value of net benefits from investing in non-pipe solutions would change under each. Of course, there could be hybrids of the three scenarios as well. And there could be variations on the second and third scenarios in terms of the timing of requirements. Such hybrids and variations could also be considered.

A hypothetical example can help to conceptually illustrate the importance of multiple scenario analyses. Consider the three scenario assumptions in Table 12, along with the related graphic depictions of demand growth without non-pipe solutions in Figure 6, and with non-pipe solutions in Figure 7. As Figure 6 shows, under the electrification scenario the duration and the magnitude of the need for additional capacity is very different than under the other two scenarios. As Figure 7 shows, because the maximum load without a non-pipe solution never gets to be more than 4% higher than the existing capacity, it is possible to completely eliminate the need with five years of a non-pipe solution.

*Table 12: Hypothetical Characterization of Three Scenarios for Gas Infrastructure Need*

| Scenario | | 2024 Peak Demand | Max Capacity w/o Upgrade | Annual Demand Growth 2025 to 2029 | 2030 to 2034 | 2035 to 2039 | 2040 to 2044 | Max Annual EE IRPA Savings | Year Upgrade Needed w/o IRPA | Upgrade Deferral Year w/Max EE |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Business as Usual | 94 | 100 | 2.0 | 2.0 | 2.0 | 1.0 | 1.0 | 2027 | 2030 |
| 2 | GHG Regs - Electric/RNG/H2 | 94 | 100 | 2.0 | 1.5 | -1.0 | -2.5 | 1.0 | 2027 | 2031 |
| 3 | GHG Regs - Electrification | 94 | 100 | 2.0 | 0.0 | -6.0 | -6.0 | 1.0 | 2027 | indefinitely |

*Figure 6: Peak Loads Relative to Maximum Capacity without Non-Pipe Solution*

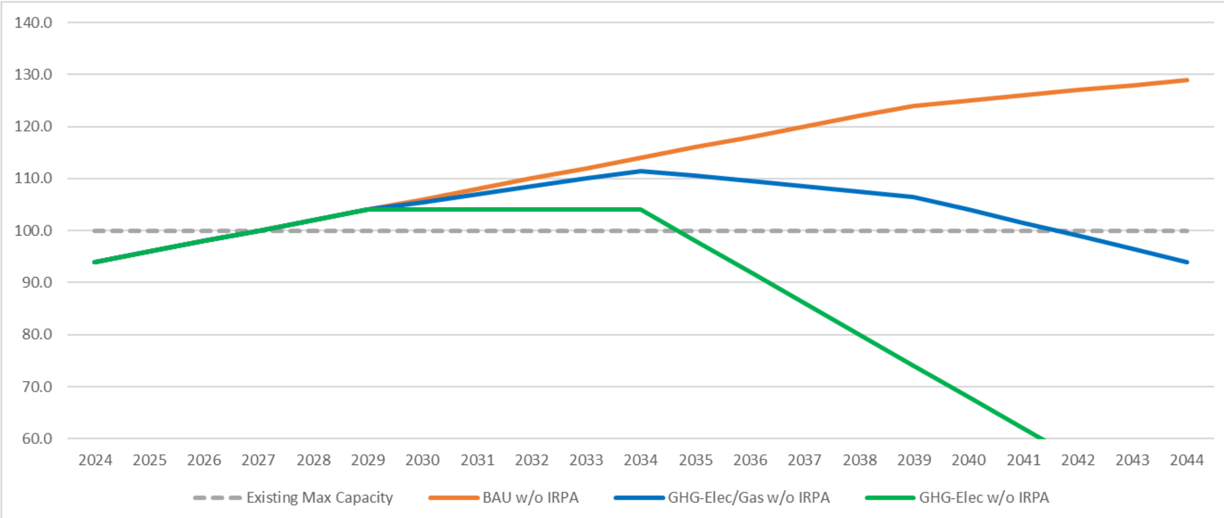
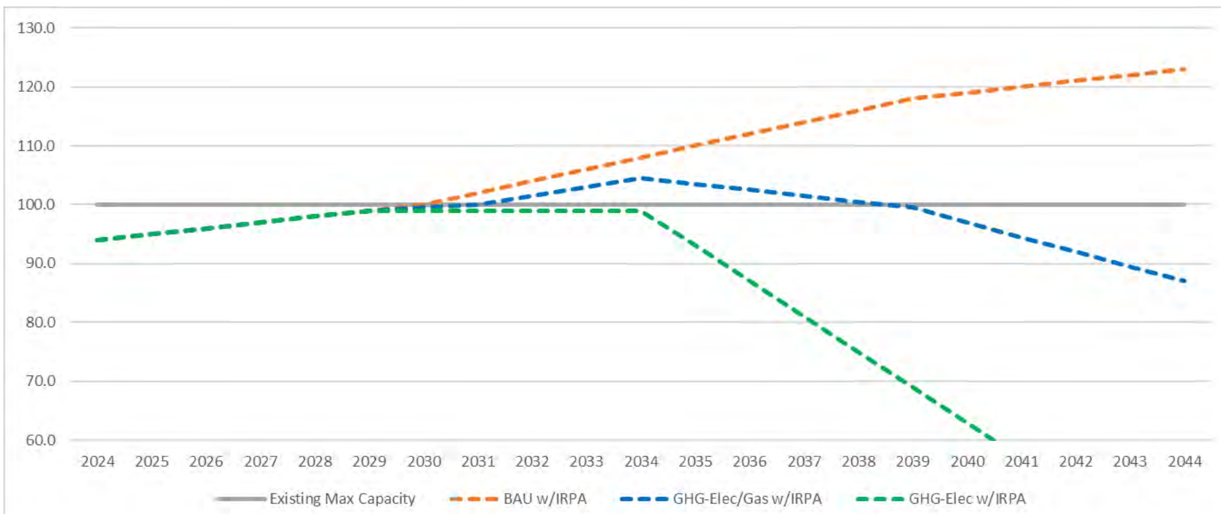



*Figure 7: Peak Loads Relative to Maximum Capacity with Non-Pipe Solution*[130]




Importantly, different scenarios could not only affect the viability a non-pipe solution for addressing reliability needs; they could also affect the economics of non-pipe solutions. Consider the hypothetical societal economics of the non-pipe solution scenarios example presented in Table 13. In this simplified example, the cost of the infrastructure upgrade is $100 in 2024 dollars (column a), which translates to a net present value (NPV) of $89 (column g) if installed in 2027 – assuming a 4% real discount rate. The cost of the energy efficiency IRPA is $20. However, energy efficiency has non-T&D deferral benefits such as avoided energy costs. The hypothetical value of those additional benefits is $16 in the Business as Usual (BAU) scenario. Put another way, the value of the T&D deferral benefit would need to be greater

[130] Non-pipe solutions are assumed to run only for as many years as they can defer the infrastructure investment or – for the electrification scenario – for as long as needed before naturally-occurring (including policy driven) demand reductions without non-pipe solutions are enough to eliminate the need for continued IRPA investment.

than \$4 per year of non-pipe solution deployment in order for the non-pipe solution to be cost effective to Enbridge customers as a whole and/or society.

Under the BAU scenario, six years of the non-pipe solution – from 2024 to 2030 – would be required to defer the T&D upgrade by three years from 2027 to 2030. If the upgrade is deferred to 2030, the NPV of the project cost would decline to \$79 (column h), or a \$10 savings (column i). That T&D deferral benefit is not enough to cover the \$21 NPV difference (column f) between six years of the non-pipe solution cost and the other non-T&D benefits provided by the efficiency programs, so the non-pipe solution would not be cost-effective. However, the non-pipe solution would be cost-effective under either of the Greenhouse Gas (GHG) regulation scenarios. In the electrification/low-GHG gases scenario, the reason is that the value of avoided energy costs (column c) is assumed to be 50% greater (because of assumed very high cost of low-GHG gases) as under the Business-as-Usual scenario, making the efficiency investments cost-effective even without any T&D deferral benefit (\$12 in savings per year). In the electrification scenario, though avoided energy costs are the same as in the BAU scenario, the fact that electrification lowers peak demand relative to the BAU scenario means that the non-pipe solution completely eliminates the need for the infrastructure project. That has much greater value (column i) than just deferring it (as in the other two scenarios).

*Table 13: Hypothetical Scenarios of Non-Pipe Solution Cost-Effectiveness* [131]

| | Scenario | Cost of Infra-Structure Upgrade (2024 \$) (a) | EE IRPA Annual Cost (b) | Cost Savings (Excl T&D) from 1 Year of IRPA (c) | Net Cost (Excl T&D) from 1 Year of IRPA (d) | Years of EE IRPA Required (e) | Net Cost (Excl T&D) from Multiple Years of IRPA (f) | NPV of 2027 T&D Upgrade w/o IRPA (g) | NPV of Deferred T&D Upgrade w/IRPA (h) | NPV of IRPA Deferral Benefit (i) | NPV of Total Net Benefits of IRPA (j) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Business as Usual | \$100 | \$20 | \$16 | \$4 | 6 | \$21 | \$89 | \$79 | \$10 | (\$11) |
| 2 | GHG Regs - Electric/RNG/H2 | \$100 | \$20 | \$24 | (\$4) | 7 | (\$24) | \$89 | \$76 | \$13 | \$37 |
| 3 | GHG Regs - Electrification | \$100 | \$20 | \$16 | \$4 | 5 | \$18 | \$89 | \$0 | \$89 | \$71 |

Again, this is just a set of hypothetical scenarios presented for illustrative purposes. It is also presented only from an all customers or societal cost-effectiveness perspective. A similar comparison of the net present value of rate impacts would also be appropriate for informing decisions. Nevertheless, this example clearly illustrates how cost-effectiveness could be very sensitive to assumptions about the future, particularly with respect to climate policy. In fact, even if one assumed that there was an 80% likelihood that the BAU scenario would become reality, and that there was only a 10% chance of each of

[131] Note that the net benefits shown in the last column of this table is only illustrative of the cost-effectiveness of a non-pipe alternative in the context the hypothetical futures characterized. It does not suggest that a renewable gas approach to addressing climate policy goals would be lower cost than an electrification approach. Economic trade-offs between renewable gas and electrification would need to be assessed under an IRP analysis applied to the entire energy system, including gas commodity costs and the costs of electric alternatives, rather than to just non-wires alternatives to traditional T&D investments. In fact, it is possible, if not likely, that non-pipe solutions would look better under a renewable gas scenario than under an electrification scenario precisely because a switch to renewable gas would be more expensive (leading the avoided costs of gas, a potentially key benefit in deploying non-wires solutions, to be dramatically higher) than electrification.

the other two scenarios becoming reality, the probability weighted average result would be that the non-pipe solution was cost-effective (i.e., a different conclusion than if one only looked at a BAU scenario).

The Board, Enbridge and other stakeholders should have the opportunity to see how these different future scenarios affect the cost-effectiveness of IRPAs.  While it will always be impossible to empirically assign probabilities to each scenario analyzed, it is important that all parties understand how sensitive the cost-effectiveness of different solutions are to assumptions about the future. In the hypothetical case presented here, the business-as-usual load forecast would have to have a nearly 90% probability of being the most accurate forecast for a traditional supply-side investment to be the most cost-effective solution. Given what we know about current government policy and related market trends, that should raise concern about approving such an investment. On the other hand, if an IRPA was cost-effective only if one assigned a 90% probability to a fully electrified future with dramatic annual reductions in peak demand beginning within the next 5-10 years, the decision might be very different.

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# EFG Phase 1 Evidence Summary

EB-2024-0111

**Chris Neme**

December 11, 2024

# Background: Chris Neme

- Expert witness in approximately 25 OEB cases
- On many OEB committees, often appointed by Board staff or elected by intervenors (e.g. DSM evaluation committees, gas IRP TWG, DSM SAG)
- Led or played major role in several gas decarbonization studies (e.g. Massachusetts, Vermont, etc.)
- Advised energy regulators, utilities, government agencies and other organizations in more than 30 states, 7 Canadian provinces and several European countries over 3 decades
- Defended expert witness testimony in approximately 70 cases before regulatory commissions in 13 different jurisdictions

See Chris Neme CV & EFG Experience with Energy Transition Issues

# Overview

- Major declines in peak and annual gas demand very likely result of decarbonization
- Implications of declining demand:
  - Increased risk of underutilized/stranded assets
  - Future ratepayers saddled with paying high rates for those assets
  - Inequities between customers today and those left on the system later
    - Esp. future customers paying for assets built to meet current customer needs
    - Esp. for low-income households who face barriers to leave the system
- EFG Report recommendation #6: reduce capital spending where possible
- Adding customers is inconsistent with a least-cost decarbonization pathway for buildings
  - The relative economics of electrification are most compelling in new construction and/or when gas system connection costs can be avoided

See EFG Report p. 4 & 49

# Major declines in demand very likely

- Gas combustion = major source of GHG emissions
  - 1/3rd of Ontario's emissions
- Electrification = cheapest way to decarbonize for society
  - Independent studies: most cost-effective pathway dominated by electrification
- No technical barriers to electrification
  - In contrast, there are many technical barriers, uncertainties and supply limitations for lower-carbon gaseous fuels
- Heat pumps → lower energy bills
  - Heat pumps result in lower residential energy bills – even today – vs. fossil fuel heating
  - Customer economics even more compelling relative to much higher cost RNG
- Even Enbridge's study would show that high levels of electrification would be lower cost once some basic analytical errors were corrected

See EFG Report p. 8; 8-41

# Decarbonization pathways studies

- Independent studies find the most cost-effective pathways to decarbonize buildings are dominated by electrification
- Examples:
  - Quebec (Dunsky for QC Govt): gas demand essentially disappears by 2050
  - New York State (E3 for NY Govt): accelerated electrification is most cost-effective; RNG/H2 plays “a very limited role”
  - Massachusetts (E3 for gas utilities): ~80% decline in throughput; hybrid heating playing a role; full electrification for all new construction as a “safe bet” recommendation
- Canadian Climate Institute (2024)
  - Most cost-effective pathway for Ontario involves 96% decline in gas for buildings
  - “Continued growth of the gas network is inconsistent with cost-effectively reaching net zero”

See EFG Report p. 10-18; CCI Report p 17 & 36 (https://climateinstitute.ca/wp-content/uploads/2024/06/Heat-Exchange-Report-Canadian-Climate-Institute.pdf)

# No technical barriers to electrification

| Electrification-dominated pathways | Gas-dominated pathways |
|---|---|
| • Proven technologies<br>  • Generation (e.g. wind, solar, batteries, etc.)<br>  • End-use (electric heat pumps) | • Technological uncertainty (use of H2 in appliances, gas heat pumps, CCS, etc.) |
| • No limit to clean electricity supply | • RNG potential constrained by limited feed stocks and needed for other uses<br>• H2 blending is limited |
| • Electrification can proceed piecemeal over time | • 100% H2 requires non-feasible simultaneous switchovers |

See EFG Report p. 19-22

# Heat pumps lower energy bills

- Adoption of heat pumps is likely because they lower energy bills
  - This will lower gas demand and utility revenues
- Heat pumps lower average home energy bills compared to gas alternatives
  - Energy bill reductions from electrification are over $500 annually
  - Also lower cost on a lifetime basis
  - Conclusions persist even in sensitivity analyses testing key assumptions
- Heat pumps lower energy bills even more versus low-carbon gases (e.g., RNG)
  - This is the more important comparison when considering a decarbonized future
  - EFG compared: (a) cost of heat pumps using more expensive clean electricity (per IESO decarbonization cost estimates) and (b) cost of a furnace burning RNG
  - Result: electrifying a home achieves three times the already substantial energy bill savings it provides today
  - Likely an underestimate because analysis disregards: (a) the savings from avoiding fixed monthly gas charges, (b) higher gas delivery rates due to customer declines, and (c) the cost to make-up for the fact that RNG is not carbon neutral.

See EFG Report p. 22-26

# Guidehouse shows electrification cheaper

- Guidehouse prepared a report for Enbridge in Phase 1
- It was highly flawed
- Correcting even one or a few errors showed its high-gas pathway to be more expensive for society as a whole
- See table 9 on page 41 of the EFG report

See EFG Report p. 26-41

# Customer growth capital is risky

- EFG report recommendation #6: reduce capital spending where possible
  - "The risk of underutilized and stranded assets calls for additional efforts to reduce capital spending, wherever that is possible, especially on long-lived infrastructure."
  - "Utilities and regulators always should seek to avoid unnecessary capital spending, but even greater scrutiny is required in the current context."
- Spending on customer connections is particularly risky
  - High cost of customer connections unlikely to be recouped from those customers
  - New capital has higher undepreciated balance
- Enbridge's incentives should be aligned with this capital reduction imperative to the extent possible

See EFG Report p. 49 & 42-44

ENERGY FUTURES GROUP

# Response to Enbridge re least-cost pathway

- EG says: Adding customers “is not in contradiction to an affordable energy transition at least cost to ratepayers (i.e. leveraging gas for peak days could be cheaper than the buildout of electric to meet peak demand).”
  - Adding customers is inconsistent with a least-cost decarbonization of buildings
  - Even Mass. pathways study recommended all new connections be electric
  - CCI report:
    - “Continued growth of the gas network is inconsistent with cost-effectively reaching net zero”
    - “low-carbon gases like hydrogen and biomethane will not serve as replacement fuels on a scale that can justify continued gas network expansion”
    - “these gases are either too scarce or too costly to heat more than a small fraction of Canada’s buildings, and are instead taken up by other sectors such as heavy industry. Even under lower-cost assumptions for these fuels, electrification of building heat still dominates.”
  - See also slide 1 re decarbonization pathways studies

See EG Response to ED Question #2; EFG Report p. 10-18; Hearing Transcript Vol. 6, p. 68, ln 25; CCI Report p. III & 36 (https://climateinstitute.ca/wp-content/uploads/2024/06/Heat-Exchange-Report-Canadian-Climate-Institute.pdf)

# News and Updates

< Back to News Releases

## Electricity Demand in Ontario to Grow by 75 per cent by 2050

October 16, 2024

According to a new annual forecast from the Independent Electricity System Operator (IESO), electricity demand in Ontario is anticipated to grow 75 per cent by 2050, higher than previously forecast, with annual consumption rising from 151 terawatt-hours (TWh) in 2025 to 263 TWh in 2050.

The accelerated pace of demand growth in this year's forecast is primarily attributed to the industrial sector, which includes additional electric vehicle supply chain manufacturing; and energy-intensive data centres, a trend that is quickly emerging around the world to support the proliferation of artificial intelligence. An increasing population and focus on electrification are other factors continuing to escalate electricity demand across the province.

"The rising growth forecast is a positive reflection of Ontario's reliable, affordable, and sustainable electricity grid, which continues to attract new investment in our province," said Lesley Gallinger, President and CEO, the IESO. "Through our robust procurement process, we have secured supply to meet Ontario's needs through the end of this decade. With growing demand, our focus is on accelerating the pace of new electricity infrastructure development across the province so that we can support the province's continued growth into the 2030s."

By regularly forecasting future electricity needs, the IESO informs electricity investment decisions and sets the context for resource procurements. A procurement for new electricity generation and storage resources is currently being finalized, with targets and timelines that will reflect faster demand growth. All forms of electricity supply will compete, securing the best price for Ontarians.

"Ontario needs to generate more power, and our government has the plan to build out affordable, reliable and clean energy for our families and future generations," said the Hon. Stephen Lecce, Minister of Energy and Electrification. "Above all, we must act with speed and urgency to ensure we think long-term and build for the future while avoiding short-sighted ideological policies that almost always lead to higher energy bills. Our vision is well underway as we lead the largest nuclear expansion on the continent on time and on budget. However, we must and will do more to decisively meet emerging supply gaps. In the days ahead, we will build upon our plan by significantly expanding energy generation, conservation and storage to keep the lights on and energy bills down for Ontario families."

The demand forecast is the cornerstone of the IESO's *Annual Planning Outlook.* The Outlook includes updated projected electricity demand, resource adequacy assessments, transmission considerations, and identifies the province's energy and capacity needs. The next *Annual Planning Outlook* is scheduled for release in Q1 2025. The new demand forecast is being released early to support ongoing engagement with stakeholders and communities.

**Quick Facts:**

- Data centers represent 13% of new electricity demand and 4% of total anticipated Ontario demand in 2035. A recent Electric Power Research Institute report forecasts that data centres could make up to 9% of demand in the United States by 2030.
- Industrial demand is forecast to grow 23 TWh or 58% by 2035 as new electric vehicle and supply chain facilities are constructed, almost equivalent to adding a city the size of Toronto to the grid.
- Ontario's households are expected to grow 15% by 2035, or one million more homes, which accounts for 6 TWh or 9% of new electricity demand.
- Electric vehicle adoption is expected to significantly reduce economy-wide emissions, and represents the largest driver of increased electricity demand, with 20 TWh or 31% of new demand by 2035.
- Since May 2023, the IESO added more than 3,600 MW of new capacity to Ontario's grid, which puts Ontario's electricity system in a strong reliability position through the rest of this decade. New supply is now needed for the 2030s and on.
- Energy efficiency is a critical resource when considering options to meet growing needs: it is the cleanest and lowest cost resource, offering customers the tools they

need to save money on their bills. Thanks to energy efficiency programs, provincial energy demand is 15 per cent lower today than it otherwise would be.

**About the IESO**

The IESO operates Ontario's power grid 24 hours a day, 365 days a year, ensuring Ontarians receive a reliable and cost-effective source of power when and where they need it. It works with sector partners and engages with communities across Ontario to plan and prepare for the province's electricity needs now and into the future.

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**IESO Media Relations**
416-506-2823
media@ieso.ca

**Andrew Dow, Sr. Manager, Public Relations**
647-330-5228
andrew.dow@ieso.ca

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OCTOBER 16, 2024

# 2025 Annual Planning Outlook: Demand Forecast Information Session

Resource Planning | Demand and Conservation Planning

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# Welcome and Introduction

- This engagement is conducted according to the IESO Engagement Principles
- Today’s session will be recorded and available for viewing online
- All documents associated with this engagement can be found on the Annual Planning Outlook webpage

# Participation

- For questions and comments click on the “raise hand” icon (hand symbol) at the top of the application window.
  This will indicate to the host you would like to speak
- To unmute audio, click on the microphone icon at the top of the application window
- Audio should be muted when not asking a question
- If experiencing connection issues contact engagement@ieso.ca or Microsoft Office Support

# Today's Discussion

- This information session will provide an overview of the upcoming APO demand forecast, including a discussion on key growth drivers and associated uncertainties
- While this is an information session, we welcome your feedback and will take it into consideration for future planning

# Background

- The Annual Planning Outlook (APO) presents system reliability needs.
- The next report, anticipated for Q1 2025, will present forecast electricity demand, the supply and transmission outlook, and system needs for 2026-2050. It will discuss risks and uncertainties and specify acquisition targets and mechanisms to meet needs.
- Ontario is attracting investment from around the world and the economy is growing. With the system quickly evolving and the need for electricity resources increasing, the IESO is presenting the 2025 APO demand forecast now to ensure the sector is informed.

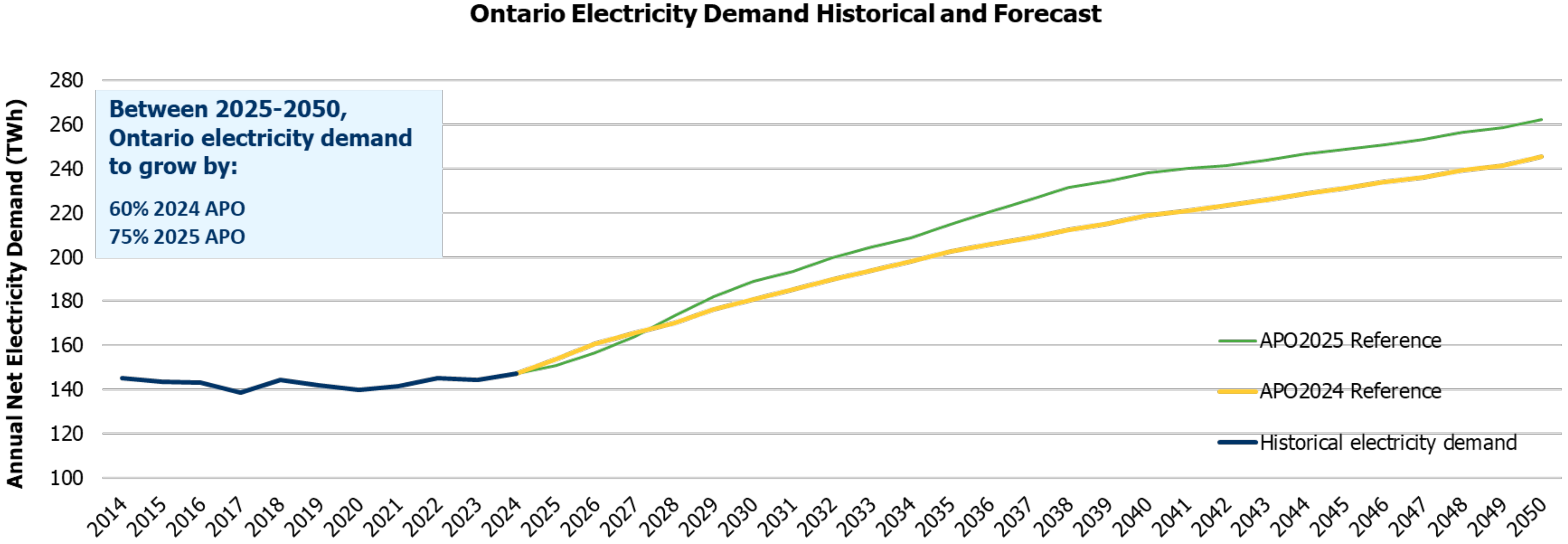
# 2025 APO Demand Forecast

# Summary

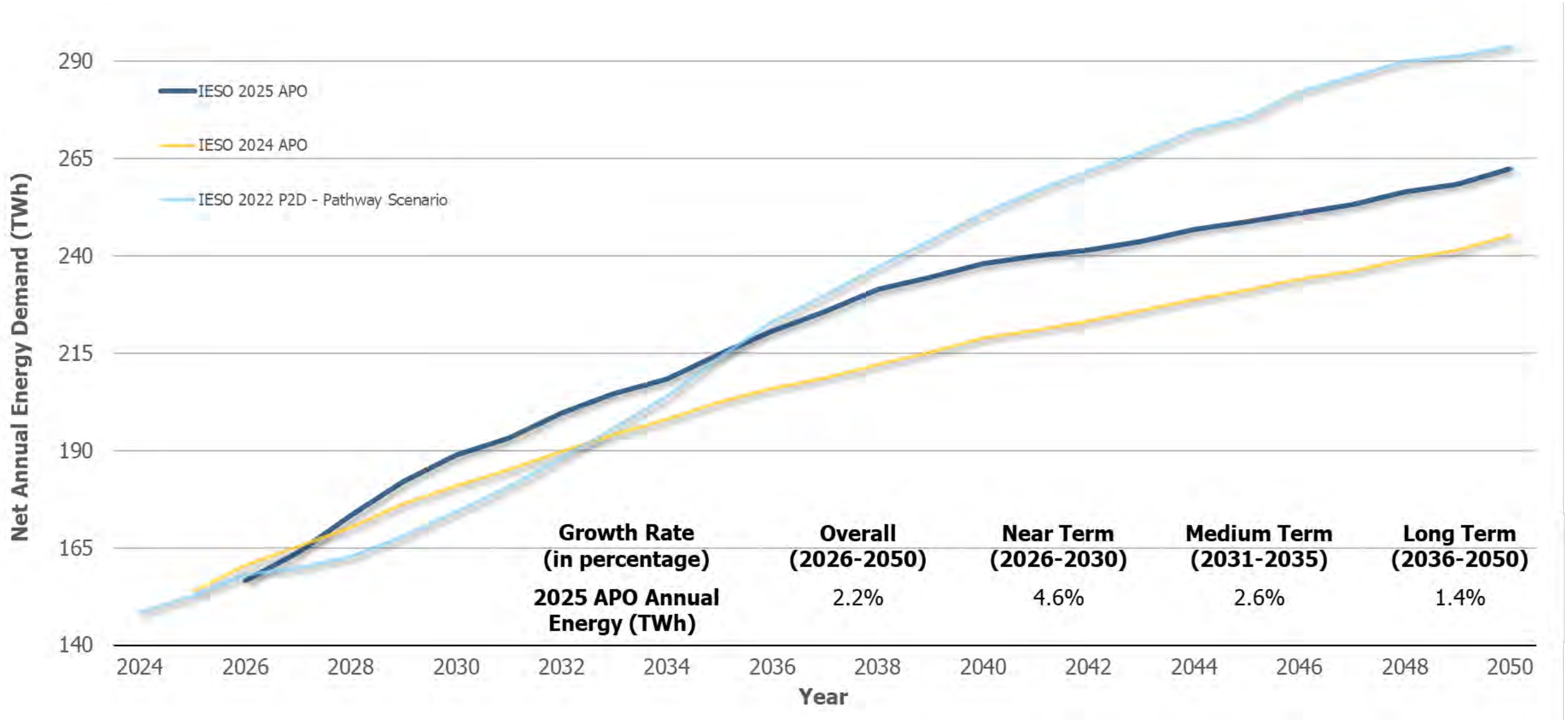
- Electricity demand is forecast to increase 75% by 2050, which is higher than the 60% increase previously forecasted.
- Industrial sector and data centre growth are the primary drivers of new demand.
- Commercial sector growth, increasing population, and electrification are also continuing to escalate electricity demand across the province.
- A procurement for new electricity generation and storage is being finalized, and targets and timelines will reflect faster demand growth.
- This work complements the many other actions underway, such as new nuclear, transmission, and demand side management programming.

# Annual Energy Demand Forecast

- Electricity demand is forecast to grow by **75% by 2050**.



# Annual Energy Demand by Forecast




| Growth Rate (in percentage) | Overall (2026-2050) | Near Term (2026-2030) | Medium Term (2031-2035) | Long Term (2036-2050) |
|---|---|---|---|---|
| **2025 APO Annual Energy (TWh)** | 2.2% | 4.6% | 2.6% | 1.4% |



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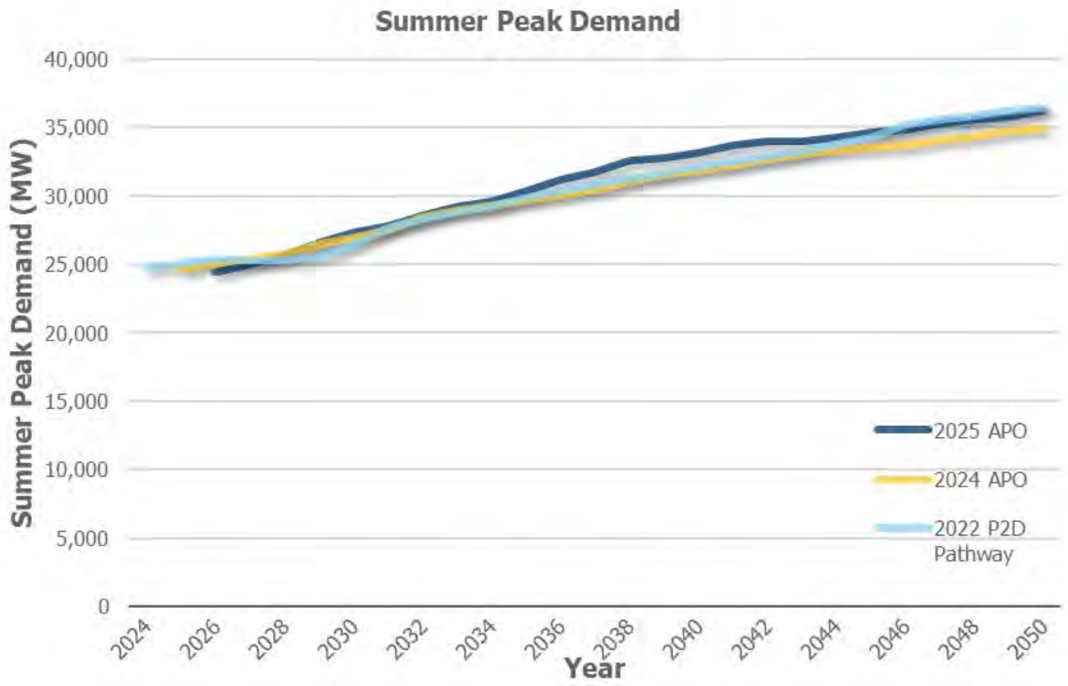
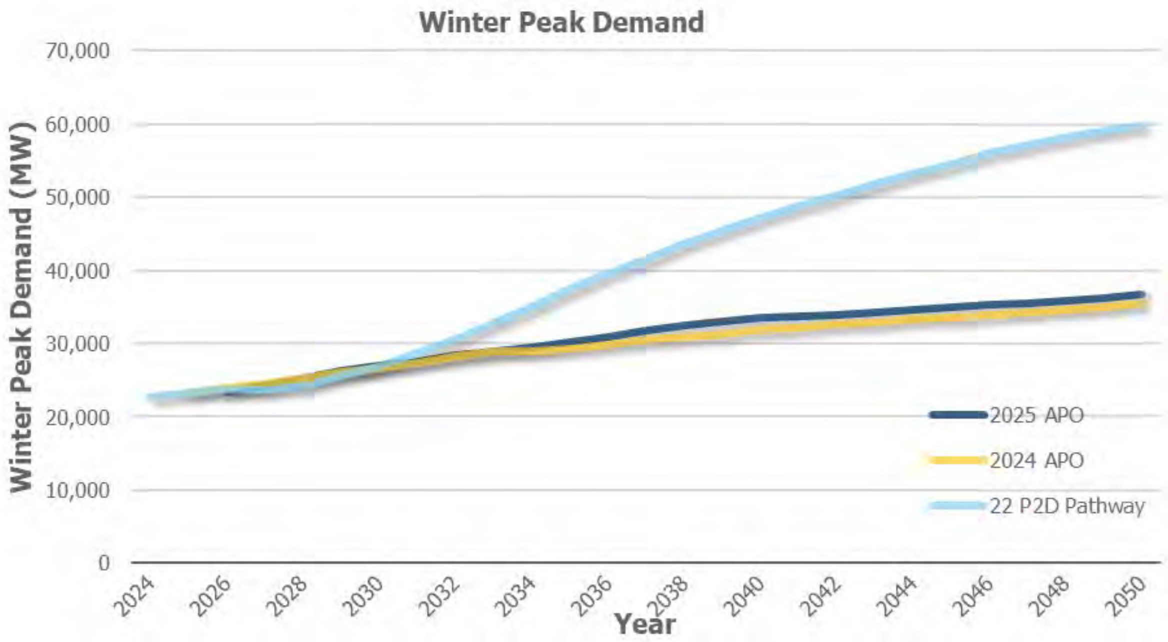
# Seasonal Peak Demand

The system is forecast to become dual-peaking by 2030, with summer and winter peaks both around 27 GW

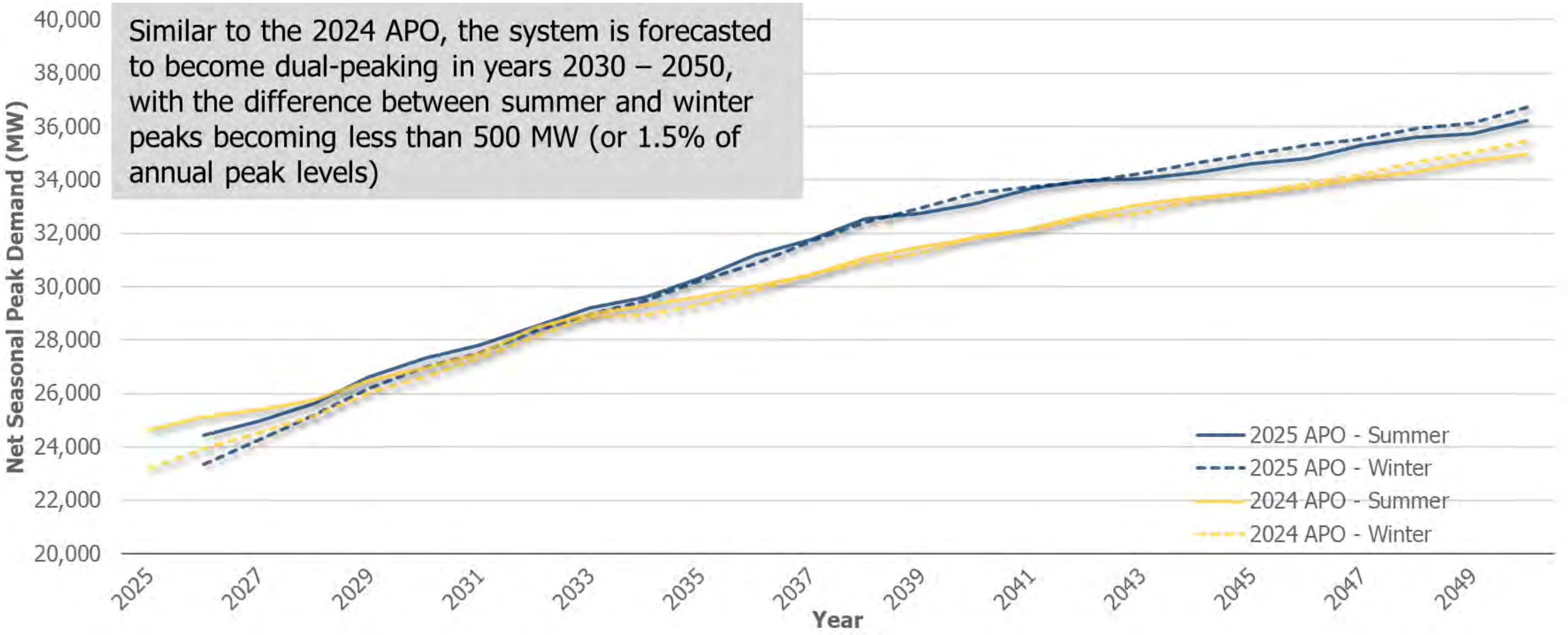



**Average Annual Growth Rate Over Forecast Period**

| | 2025 APO | 2024 APO | 2022 Pathways to Decarbonization (P2D) Study |
|---|---|---|---|
| Summer Peak | 1.7% | 1.5% | 1.5% |
| Winter Peak | 2.0% | 1.8% | 3.8% |



# System



Similar to the 2024 APO, the system is forecasted to become dual-peaking in years 2030 – 2050, with the difference between summer and winter peaks becoming less than 500 MW (or 1.5% of annual peak levels)
Net Seasonal Peak Demand (MW)
40,000
38,000
36,000
34,000
32,000
30,000
28,000
26,000
24,000
22,000
20,000
2025
2027
2029
2031
2033
2035
2037
2039
2041
2043
2045
2047
2049
Year
2025 APO - Summer
2025 APO - Winter
2024 APO - Summer
2024 APO - Winter

# Key Statistics & Drivers

## 2025 APO -

- **Energy:** grows 75%, from 151 TWh in 2025 to 263 TWh in 2050.
- **Summer Peak:** grows 50%, from 24,000 MW in 2025 to 36,240 MW in 2050
- **Winter Peak:** grows 60%, from 22,650 MW in 2025 to 36,740 MW in 2050

## 2025 APO vs 2024 APO -

- **Annual energy** is 12 TWh higher in 2035 than the 2024 APO
- **Summer peak** is 700 MW higher in 2035 than the 2024 APO
- **Winter peak** is 900 MW higher in 2035 than the 2024 APO

# Demand Growth Overview

- The 2025 Forecast has higher demand growth in the near- and medium-term compared to the 2024 Forecast
- Demand growth influences are attributed to the following:
  - Specific commercial and industrial sector updates with significant new projects, and expected electrification at existing facilities (known as “Large Step Loads”), largely in the near- and medium-term
- Demand reduction influences are attributed to the following:
  - Updated energy efficiency program savings
  - Decreased demand in the agricultural sector
- Significant uncertainties exist with many of these factors

# 2025 Forecast Updates – Factors Increasing Demand

**Increases are attributed to:**

- Inclusion of a substantial amount of new large potential and confirmed projects such as:
  - Data centres
  - Commercial sector building electrification
  - Industrial electric vehicle production and supply chain sub-sector
  - A small number of industrial sector economic development and electrification activities

with commensurate level of increased uncertainty (project materialization, levels of demand, implementation timing, etc.)

# 2025 Forecast Updates – Factors Tempering Demand

**Changes in 2025 APO throughout all years that temper increases:**

- Agricultural sector – softening in West of London greenhouse sub-sector development
- Higher energy efficiency program savings forecast based on updated program information and enhancements
- Increased Industrial Conservation Initiative response commensurate with forecasted increased industrial sector electricity demand
- Increased Peak Perks program demand savings forecasts based on first year results

# 2025 Forecast Updates – Previously Established Factors

**Factors, drivers or sector electricity demand with no major variances with 2024 APO:**

- Residential sector
- Commercial sector (excluding data centre sub-sector)
- Industrial sector demand (excluding automobile production updates; including northern Ontario mining long term development and electrification)
- Transportation sector
- Long term economic and demographic outlook

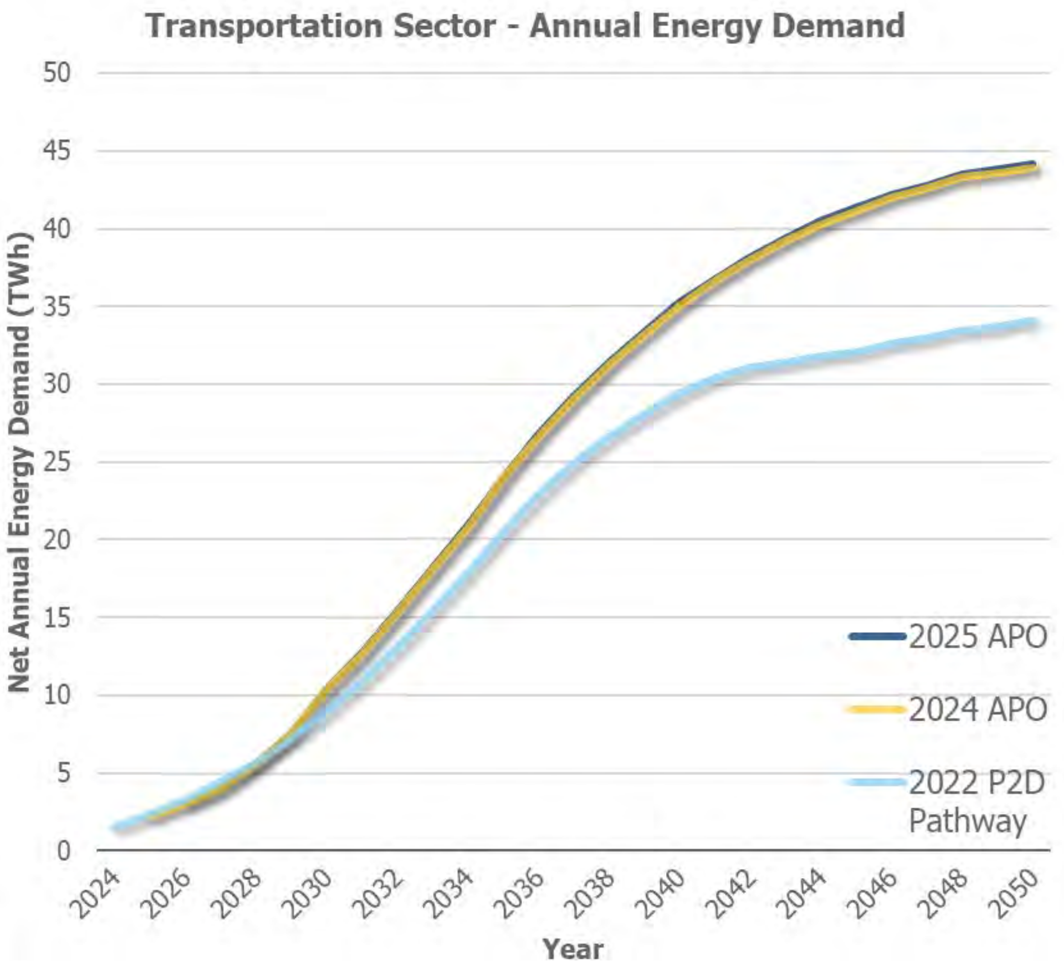
# Sector-Level Insights

# Transportation Sector

The numbers in the APO are aligned between the 2024 and 2025 forecasts. They are higher than the P2D forecast, which is consistent with the 2022 APO.

Transportation electrification includes EV and Rail projects (LRT, GO rail, and new subway).

Includes federal LDEV target of 100% by 2035; and 60% by 2030.



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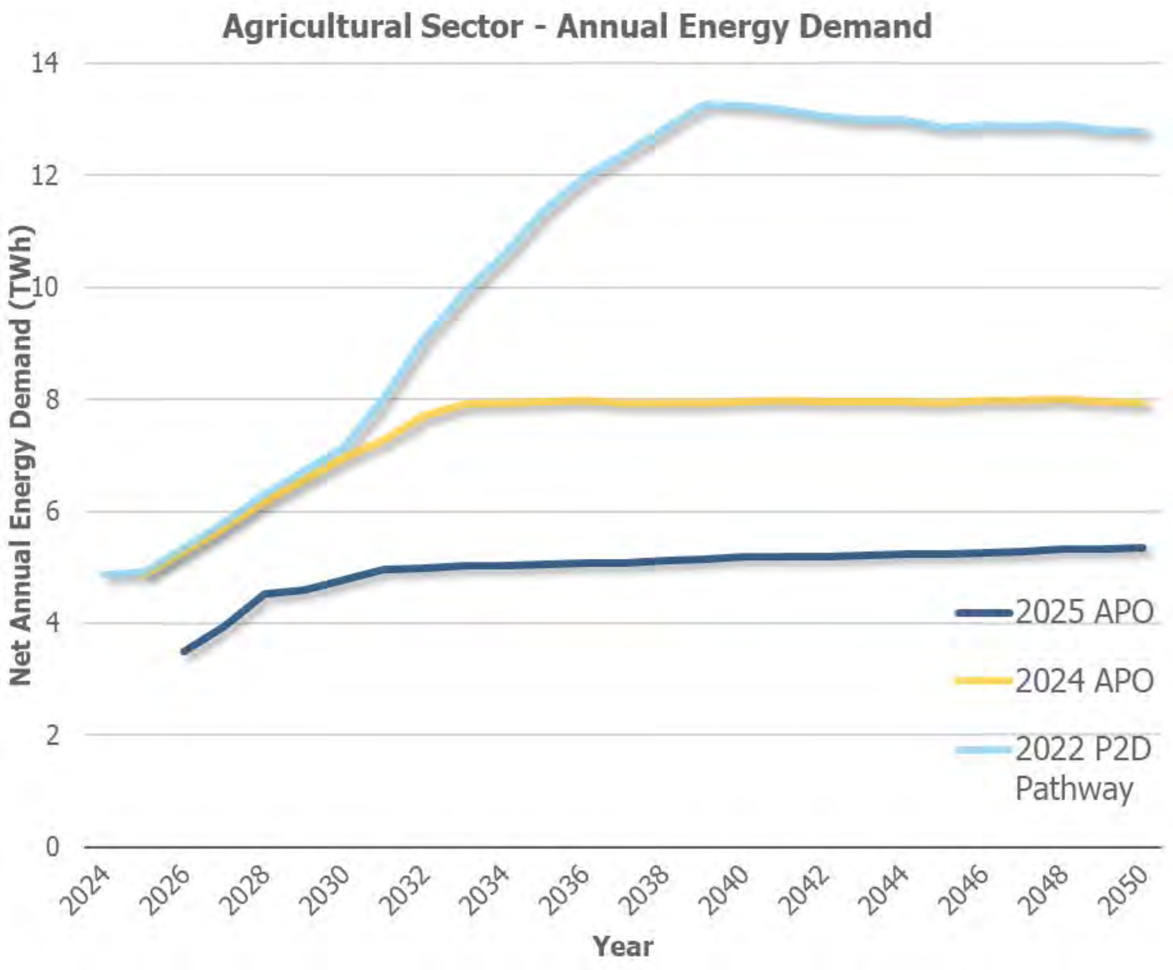
# Agricultural Sector

Agricultural demand continues to grow in the near-term, with indications of further pent-up potential in the sector.

However, long-term growth is significantly lower than the 2024 APO, based on updated forecasts of Windsor-Essex greenhouse growth.



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# Residential Sector

Ontario's households are expected to grow 32% by 2050 to 8.3 million homes, and forecasted residential demand remains consistent with the 2024 APO with the addition of moderate growth.

The 2025 APO forecast includes 373,000 incremental heat pumps by 2050.




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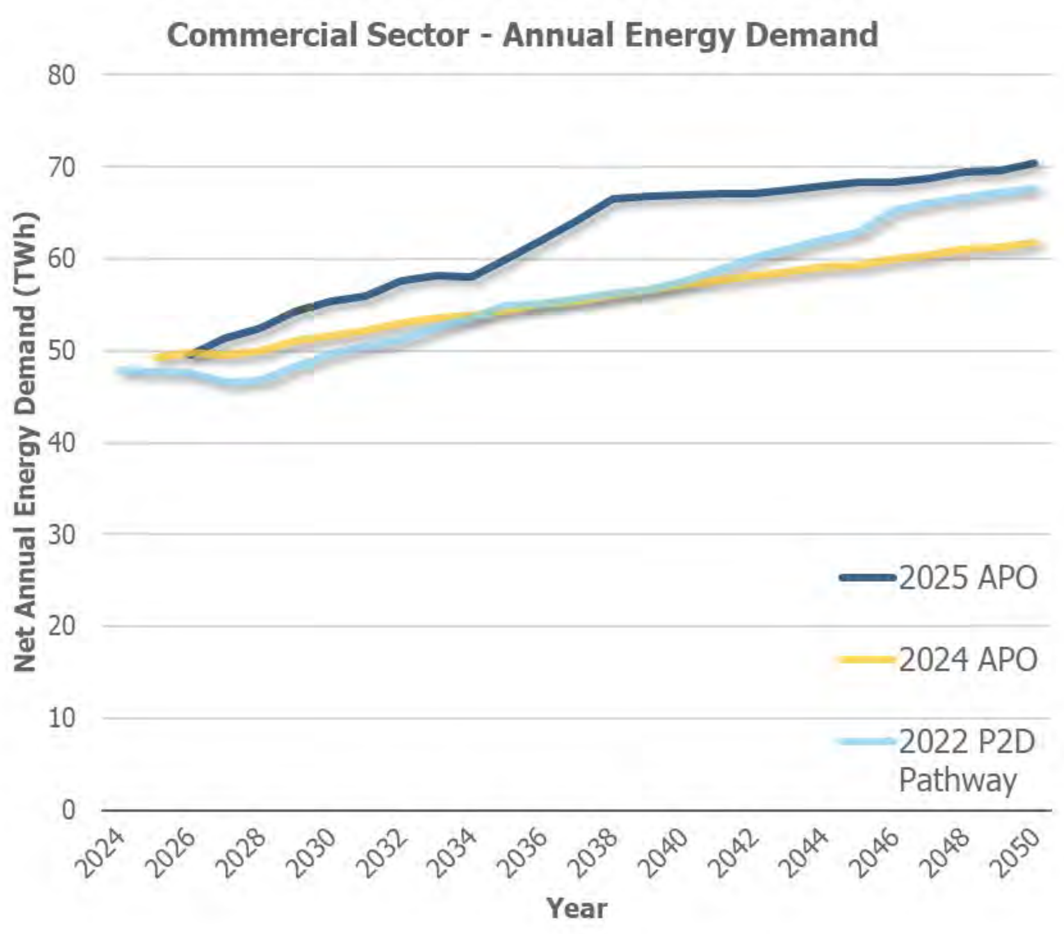
# Commercial Sector, Including Data Centres

The addition of multiple data centre projects significantly increases the 2025 commercial sector forecast, compared to the 2024 APO and P2D. Data centre project growth could be significant over the next 15 years and is one of the top two new drivers of the 2025 APO demand forecast.

Data centre demand in the demand forecast: 14 TWh/yr, or 1,600 MW from 2038-2050.

Remainder of commercial sector effectively flat; average annual energy and peak demand growth rate from 2026-2050: ~+0.6%/yr.



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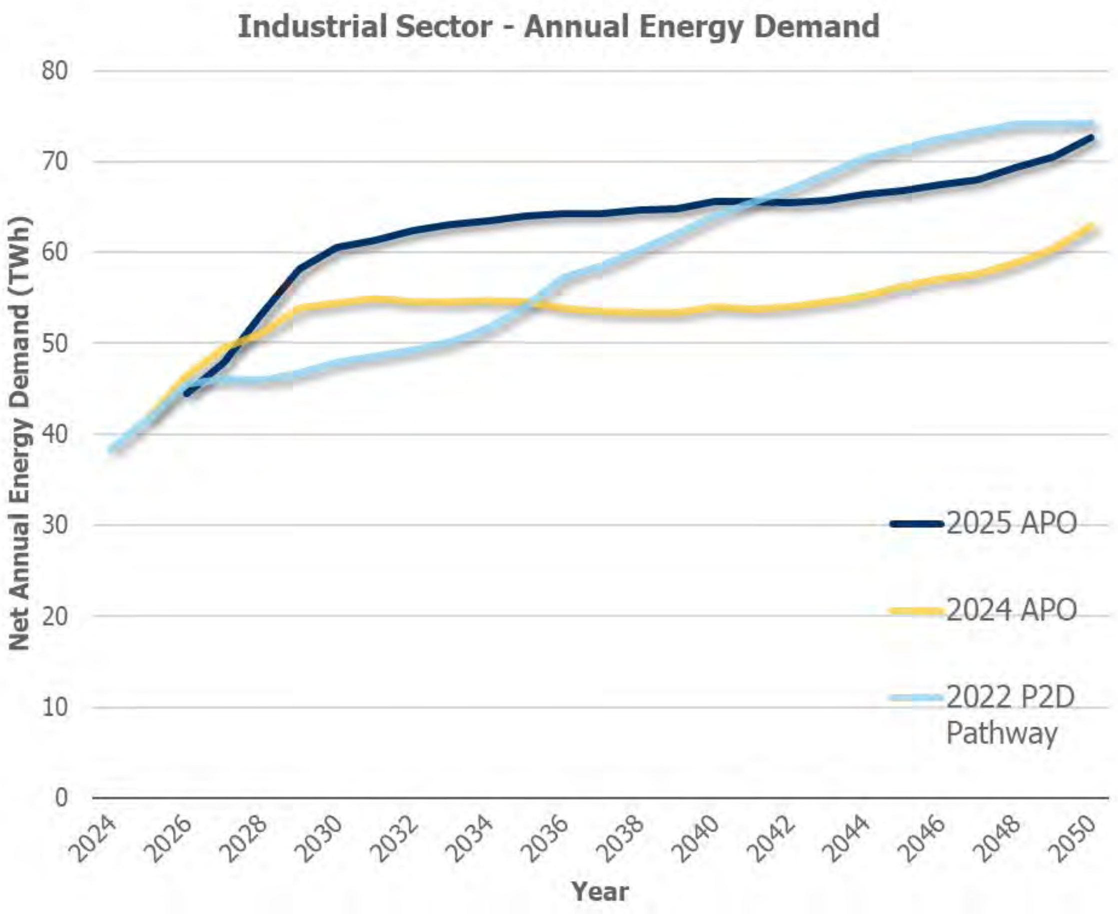
# Industrial Sector

The industrial sector demand forecast in the 2025 APO is higher than the 2024 APO due to additional growth in the EV supply chain and primary metals subsectors.

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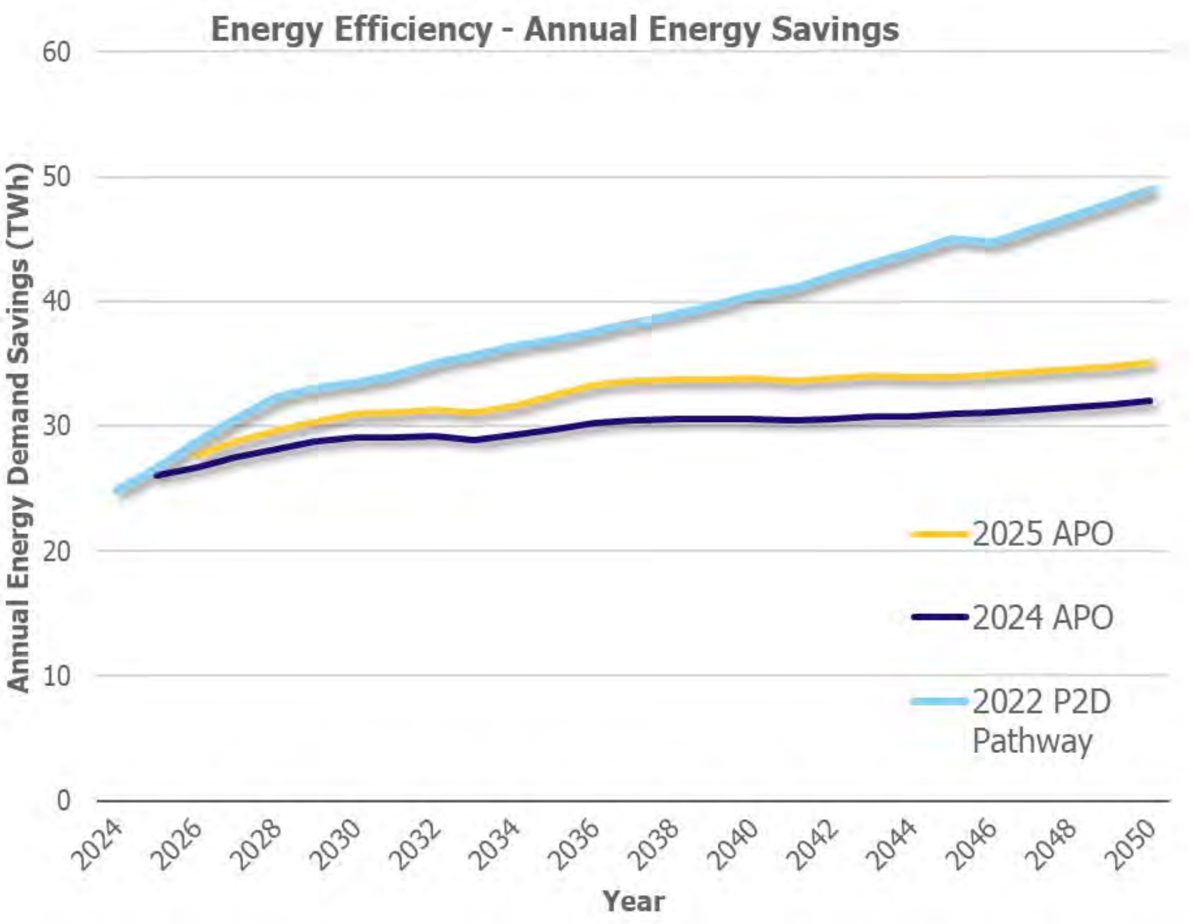
# Energy Efficiency - Annual Energy Savings

The energy efficiency savings increased as compared to the 2024 APO based on updated program information and enhancements. A similar level of energy efficiency is assumed to continue for future years. As a result, saving levels for future energy efficiency were estimated higher than previous APO forecasts.



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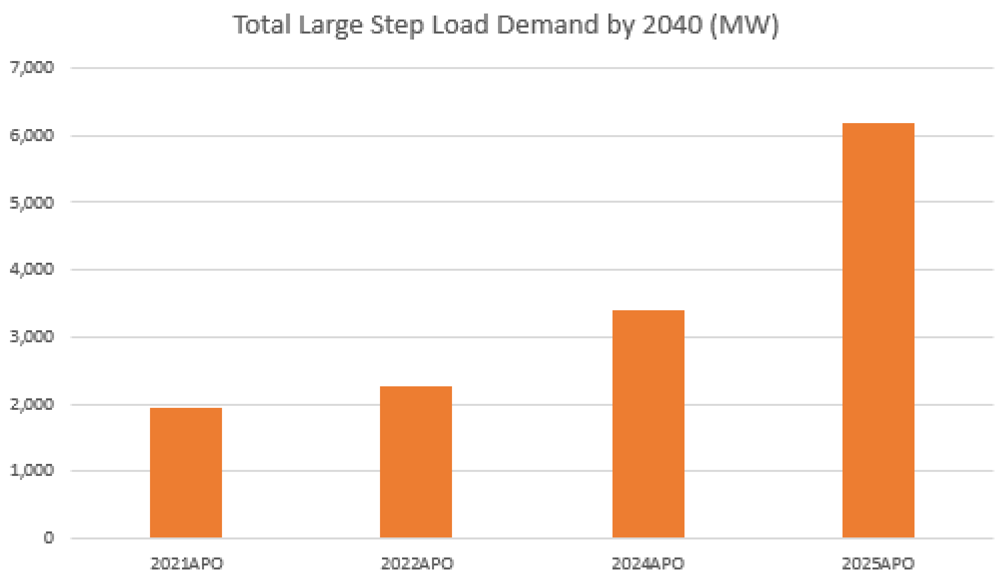
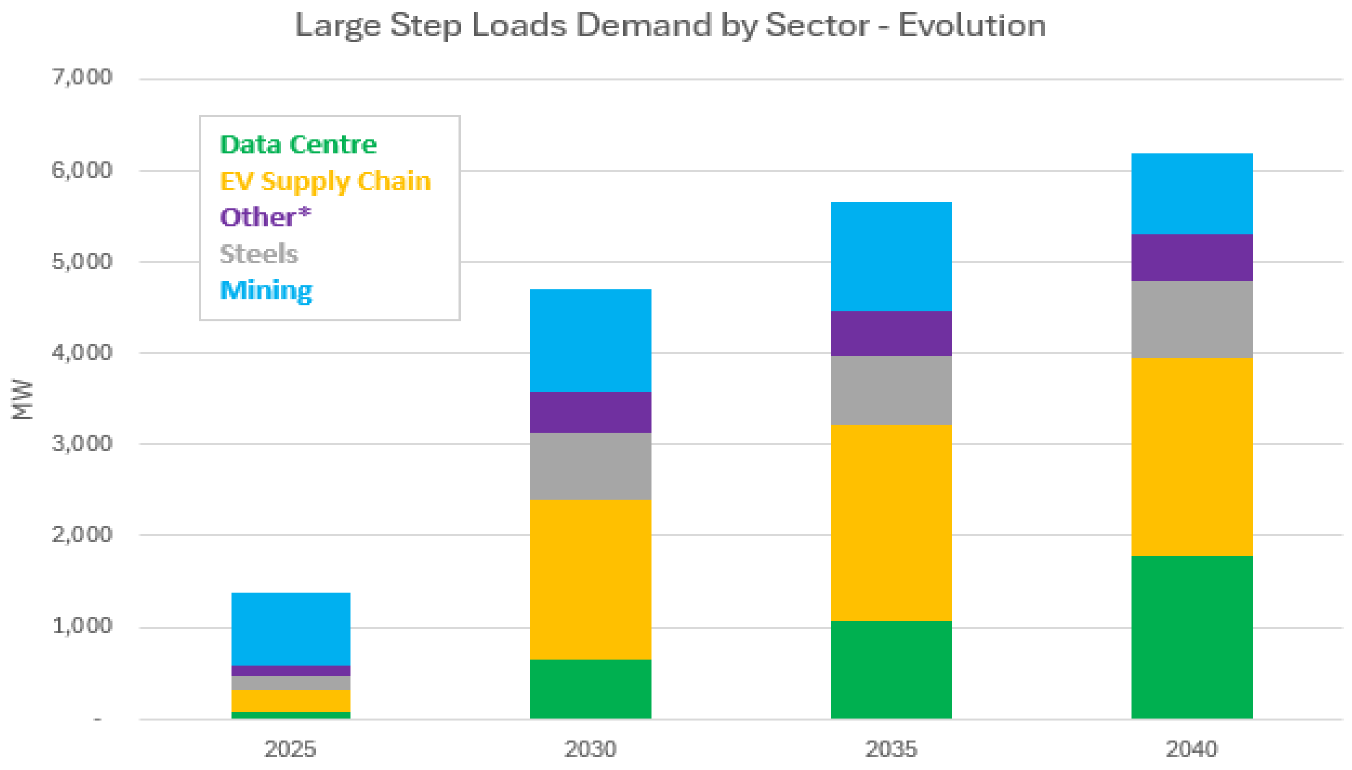
# Large Step Loads

- The forecast shows significant growth due to large step loads. There is significant uncertainty associated with large step loads, including whether projects will come to fruition and their timelines, or whether new projects will be proposed and what their potential energy needs will be.
- The forecast reflects demand from large step loads assessed by the IESO for certainty, e.g., projects that are known with certainty, have been announced, or have submitted a System Impact Assessment.
- The IESO is aware of numerous potentially upcoming projects that could significantly increase total demand. As these projects firm up, they will be evaluated and incorporated in future APO demand forecasts.



# Large Step Loads

This graph below provides an outlook of the Large Step loads included in the 2025 APO:



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# Uncertainties and Risks

- Current and near-term state of economy
- Long-term demographic, affordability and productivity trends
- Materialization of:
  - Commercial data centres, and cryptocurrency mining projects;
  - Industrial automobile production & supply chain sub-sector transition to electric vehicles
  - Hydrogen production
- Industrial mineral extraction sub-sector project development and electrification
- Electrification technology development & acceptance: buildings, vehicles, industry
- General decarbonization strategies: thermal storage & networks, distributed energy resources
- Climate change on weather sensitive load
- Policy changes

# Next Steps

# Next Steps

- Analysis to support the development of the complete 2025 APO is underway
- The release of the 2025 APO is targeted for Q1 2025
- Whitepapers exploring demand uncertainties will be released in the future
- If you have any questions on the information shared today, please contact IESO Engagement at engagement@ieso.ca

ONTARIO ENERGY BOARD

# Report Back To The Minister On System Expansion For Housing Developments

**June 28, 2024**

Ontario Energy Board

# PREFACE

On November 29, 2023, Ontario's then Minister of Energy, Todd Smith, in his Letter of Direction to the Ontario Energy Board (OEB), acknowledged the critical role the OEB plays in ensuring Ontario's electricity and gas transmission and distribution systems are built in a timely manner to support the province's ambitious housing, transportation and economic goals, while protecting ratepayers from undue hardship. The government's goals include building at least 1.5 million new homes, new highways, subways and improved rail transportation.

The Minister encouraged the OEB to review electricity infrastructure unit costs in the electricity sector and potential models for cost recovery with a view to keeping infrastructure costs low and not a barrier to Ontario's growth. In addition, the OEB was asked to review its electricity distribution system expansion connection horizon and revenue horizon direction to ensure that the balance of growth and ratepayer costs remains appropriate. In keeping with the Minister's expectations, rate affordability remains a key factor in the OEB's decision making.

The recommendations outlined in this Report demonstrate OEB's commitment to a clear, sustainable and equitable cost recovery framework, while ensuring the framework remains adaptive to Ontario's goals and the evolving energy landscape. This work also aligns with several recommendations from the Electrification and Energy Transition Panel, and in particular the recommendation that the OEB leverage its existing mandate to support activities that align with the province's objectives for a clean energy economy and the demands of Ontario's energy transition.

This Report – delivered in two parts – addresses the Minister's requests:

**Part I** provides the OEB's review of the current infrastructure cost recovery approach, specifically the connection and revenue horizons, and alternative cost recovery approaches to connecting new subdivision developments. It assesses the current framework, discusses potential options for policy changes, summarizes stakeholder feedback and sets out the OEB's recommended actions aimed at balancing housing development needs with consumer protection and rate affordability. Part I begins on page 8.

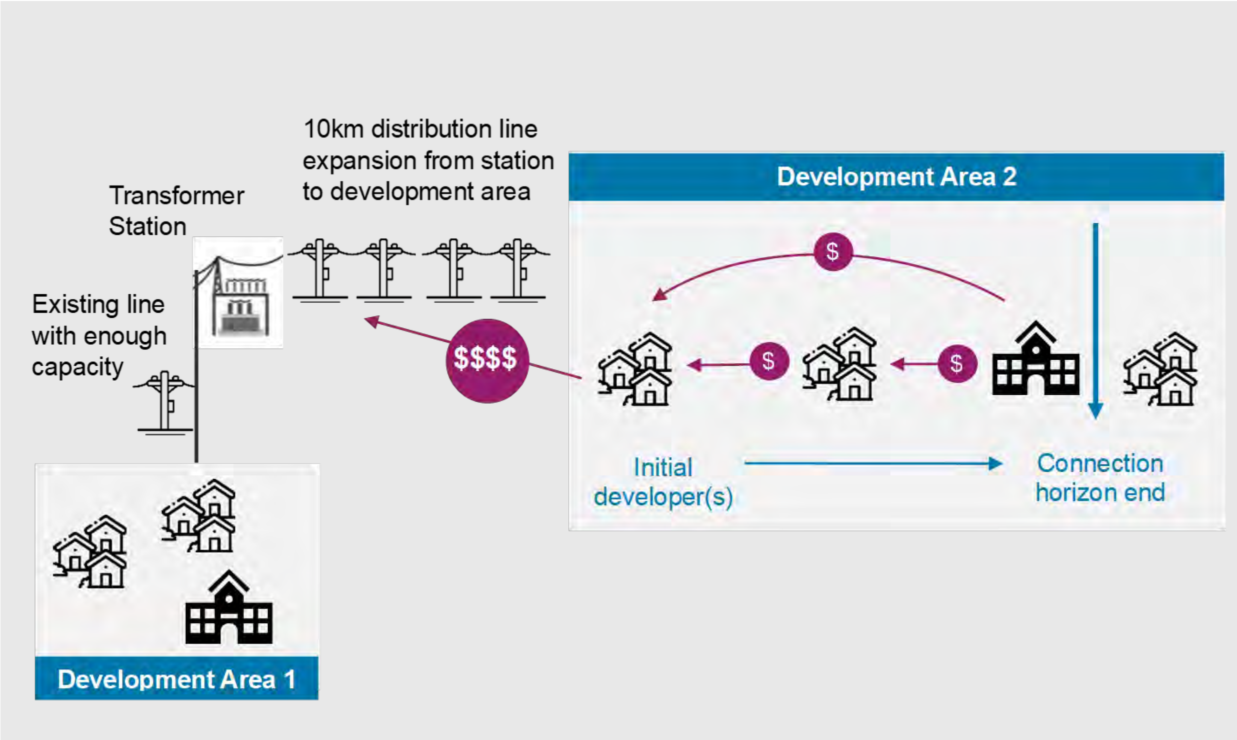
**Part II** presents findings from an OEB-commissioned study, performed by PricewaterhouseCoopers (PwC), that reviewed distribution system unit costs for connecting new subdivision developments based on a survey of six electricity distributors and identifies areas of potential improvement. Informed by the results of the PwC study, the OEB's recommended next steps in relation to unit costs are discussed below. Part II begins on page 57.

## KEY FINDINGS

**Part I** of the Report examines the OEB's cost recovery framework, including considering alternatives and the appropriateness of the connection and revenue horizons set out in the Distribution System Code (DSC). To understand the issues and formulate recommendations, the OEB consulted consumers, developers and distributors and gathered their input on issues and approaches to addressing them.


### What We Heard

Developers pointed to a need for revisions to the cost recovery framework to address challenges in multi-phase greenfield developments, specifically where the initial developers face significant costs to bring the distribution system into the development area (as illustrated below). There is strong consensus on the need for a balanced, equitable cost-sharing model that protects existing ratepayers from undue financial impacts while supporting sustainable growth. This includes calls for broader policy consultation and improved planning to tackle infrastructure challenges in emerging communities. Many developers called for a provincial roundtable to discuss these issues. Stakeholders, specifically developers, are also pressing for clearer and consistent cost recovery rules in the DSC to better manage project planning and reduce confusion.




Stakeholders generally supported extensions to the connection and revenue horizons to alleviate the financial burden on "first-mover" developers and ensure more equitable cost distribution. Ratepayer groups emphasized protecting existing customers from undue costs. Distributors highlighted the administrative challenges and potential financial implications of extending the horizons, suggesting that any changes should be targeted to specific scenarios and consistently implemented across all expansions to prevent undue complexity and discrepancies.

**Part II** of this Report examines unit cost data collected from six electricity distributors that serve areas expected to experience medium to high housing growth. The unit cost analysis was supported by in-depth surveys and interviews with the six distributors and three developers, as well as examples gathered from one interview with another regulator.

To ensure a common frame of reference and the comparability of the unit costs data, and to facilitate variance analyses and the identification of trends, OEB staff designed 10 scenarios for which estimated costs broken down by material, labour and overhead charges were collected. PwC designed surveys and performed one-on-one interviews to gather the information used in their study.

The study indicates that the average estimated unit cost for subdivision electrical infrastructure for a gas-heated community was $7,500 per lot. The range among the six distributors was $3,300 to $11,300. For an all-electric community, the average estimated unit cost was $12,200 per lot and a range of $11,900 to $12,400. The cost difference between a gas-heated community and all-electric community was attributed to an increase in cable size and increases in the number of pad-mounted transformers to serve a larger anticipated electrical load within the subdivision. These scenarios assumed there was sufficient system capacity, and no network upgrades were required. These electrical subdivision infrastructure costs make up approximately 1.5% to 3% of the average home build cost for an 1,800 square foot dwelling in Ontario. With respect to infrastructure required to supply the subdivision connection, the study identified that the average estimated unit cost for overhead primary line to be $0.5M per kilometer (the range was $0.3M to $1.1M) and the average estimated unit cost for underground primary line to be $1.6M per kilometer (the range was $0.77M to $2.7M).

PwC’s main observations are:

1. Electricity distributors in Ontario have variations in how they manage core cost components and differences in their processes.
2. Timelines, labour and material availability and cost, are considered an area of concern as development begins to accelerate.
3. Distributors and developers have begun to collaborate efficiently, finding channels for feedback with each other, however, room for improvement in collaboration still exists. OEB staff notes that this issue was also raised by developers in their comments on the cost recovery framework in Part I.
4. System capacity constraints are of significant concern, which was also a key issue identified by all developers in their comments on the cost recovery framework.
5. There are multiple other factors that contribute to housing development timelines and cost; utilities are not the bulk of it.

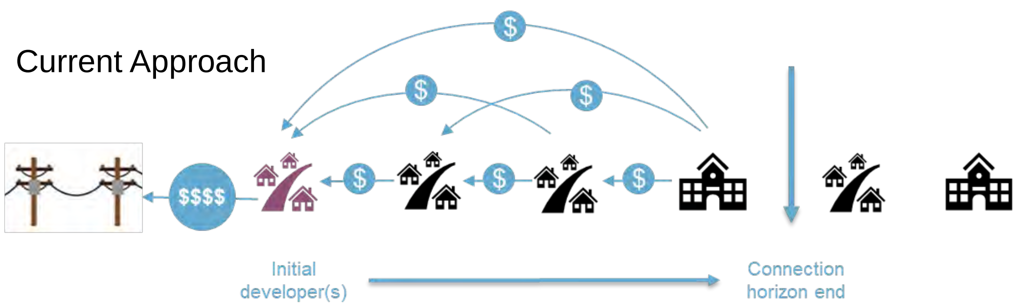
## PATH FORWARD

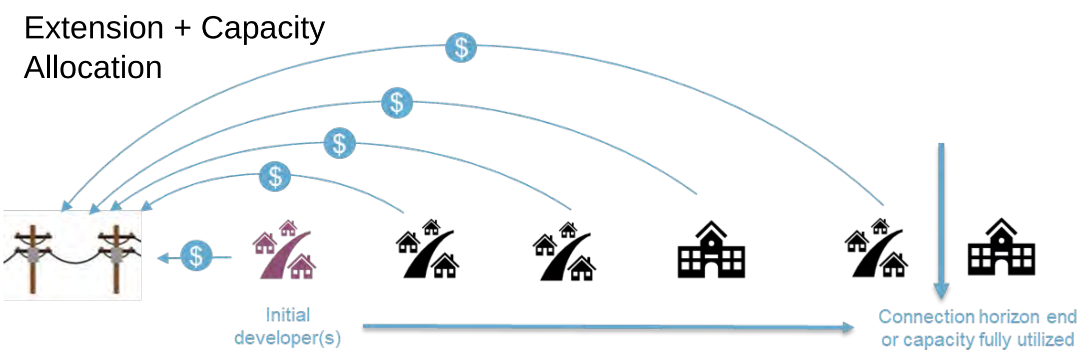
In formulating its recommendations for this Report, the OEB has taken into account the feedback from stakeholders, the relevance and effectiveness of the current cost recovery framework for other customer connections, and the concerns about administrative complexity and potential mitigation strategies. Additionally, the OEB has prioritized its recommendations based on the urgency of addressing the identified issues while emphasizing the need to maintain fairness among different customer groups and the affordability of electricity rates, in line with expectations from the Minister's letter.

**The OEB is therefore recommending the following actions:**

1. Propose new provisions for the DSC to clarify for distributors and customers how extended connection horizons beyond the standard five years should be employed.

2. Develop new DSC provisions for a capacity allocation model that specifically addresses multi-year, multi-party developments and ensures a fair allocation of costs between connecting parties.
3. Propose extending the revenue horizon used in the evaluation of expansion projects to recognize the life of assets used in connecting and serving residential customers.
4. Changes to Activity and Program-based Benchmarking (APB) monitoring and reporting, including increasing the number of unit costs that are tracked to identify best performing distributors as a means of encouraging efficiencies across the sector.
5. Develop an APB connection cost metric based on major cost factors, including individual asset types to identify and adopt best practices for enhanced cost efficiency.




The OEB anticipates that implementing the above changes to the current cost recovery framework will more swiftly and effectively address issues relating to the connection of large greenfield developments compared to creating entirely new regulatory frameworks. These adjustments aim to reduce the capital contributions needed from a single developer, by distributing costs over an increased number of developers/customers and an extended timeframe, while maintaining an appropriate allocation of risk between new and existing customers.

Changes to APB are expected to enhance transparency and consistency, which will help identify opportunities to improve cost efficiency. The development of APB connection cost metrics that encompass a broader spectrum of cost factors will facilitate more comprehensive analyses, enabling the identification and adoption of best practices by distributors that can drive efficiencies throughout the province.

In response to the Minister’s request, the OEB explored a number of alternative cost recovery approaches, focusing on their impact on greenfield developments, ratepayers, and implementation issues. Feedback from stakeholders highlighted that substantial work would be required to more fully develop and assess these alternatives. For that reason, as well as the potential risk of delays to housing projects as developers await the outcome of such consultations, the OEB suggests that that these alternatives should only be pursued if the proposed adjustments to the connection and revenue horizons do not sufficiently alleviate the financial challenges faced by initial developers.

During the consultation, stakeholders, in particular developers, raised issues related to the connection process, distributor communications, information sharing and timeliness for housing developments that are not directly related to cost recovery, but, that can impact project costs. These concerns were also raised during the interviews conducted as part of the unit cost study. The OEB plans to review these issues and will provide further guidance and direction to the industry as needed regarding regulatory requirements and performance expectations for customer connections.

This Report presents the OEB’s recommendations to support the government’s goal of building at least 1.5 million new homes and the surrounding infrastructure. As changes are thoughtfully considered and appropriately implemented, the OEB will ensure that the balance of growth and ratepayer costs remains fair, with rate affordability remaining central to the OEB’s decision making. The forward-looking plan set out in this Report not only addresses the immediate needs highlighted by developers and other stakeholders, it also supports electrification and an energy transition that is practical, affordable and transparent for all Ontarians.

ONTARIO ENERGY BOARD

## Part I

# Review of Cost Recovery Framework for System Expansion for Housing Development Connections

# 1 INTRODUCTION

In this Part, the Ontario Energy Board (OEB) provides its response to then Minister of Energy, Todd Smith's request in his November 2023 Letter of Direction that the OEB review its rules regarding cost recovery, including a specific request to review the connection and revenue horizons, related to electrical distribution system expansions for connecting housing developments.

To understand the issues and formulate recommendations, the OEB consulted consumers, developers and distributors to gather their input on issues and approaches to addressing them. More than 150 participants attended the April 3, 2024 stakeholder meeting from 50 different organizations – representing 15 developers, nine consumer groups, 30 distributors and other government organizations. Furthermore, the OEB received 19 written submissions from five developers and one developer association, five consumer groups, five distributors and two distributor associations, and one municipal representative.

Based on stakeholders' feedback, the OEB recommends that it move ahead with specific changes to the current cost recovery framework to address challenges related to large greenfield developments. Specifically, these developments may require significant system expansions to bring electrical infrastructure to development areas. This requires developers to make large upfront financial commitments to distributors that they consider an unfair burden. To address the urgent need for supporting housing development while assuring affordability for consumers, the OEB recommends the following targeted amendments to its cost recovery rules:

- Proposing new provisions for the Distribution System Code (DSC) to clarify for distributors and customers how extended connection horizons beyond the standard five years should be employed.
- Developing a capacity allocation model that specifically addresses multi-year, multi-party developments and ensures a fair allocation of costs among connecting parties.
- Extending the revenue horizon used in the evaluation of expansion projects to recognize the life of assets used in connecting and serving residential customers.

These changes aim to enable distributors to plan and execute appropriately sized expansions for new development areas that involve multiple phases, multiple developers or customers and extend over several years. Stakeholders noted that the existing cost recovery framework is effective for the majority of customer connections and only creates challenges for development areas under specific circumstances. Stakeholders supported changes, which build on the principle underlying the current framework and will maintain fairness between new and existing customers and support energy rate affordability. The stakeholders, in particular developers, communicated the need for urgent action to address the issues identified.

The OEB believes that targeted amendments to the current framework will address the primary concerns raised by stakeholders in a timely way without raising new issues and avoiding disruption to ongoing development projects. Once the changes are implemented, the OEB, with stakeholders, can evaluate the need for other more substantive modifications to the cost recovery framework, such as the alternate cost recovery mechanisms identified in this Part.

The following sections provide a summary of the common feedback gathered from stakeholders and an overview of the current policy framework, followed by detailed discussions on the connection horizon, revenue horizon and the alternate cost recovery approaches identified during the consultation. Each section provides stakeholders' comments, as well as the OEB's analysis and recommendations. The Report concludes with a summary of recommended actions and next steps. All the cost allocation rules regarding system expansion discussed in this Report, including the two horizons, are specified in the DSC.

*Note: Examples used throughout this Report are intended to illustrate various concepts described. They may not necessarily cover all the relevant Distribution System Code (DSC) rules.*

# 2 COMMON FEEDBACK

Most stakeholders suggested that the housing development challenges are related to large greenfield developments, where significant system expansions are required to bring the electrical infrastructure to the development areas. Stakeholders unanimously agreed on the need for thorough consultation and analysis before making significant policy changes. All stakeholders emphasized the importance of an equitable cost-sharing approach that prevents undue financial impact on new developments, while ensuring existing ratepayers are not unfairly impacted. Most stakeholders also recognized, and developers were emphatic, that a quick solution is required if the government's housing goals are to be met.

Overall, stakeholder feedback can be grouped into four main areas that we explore in detail below:

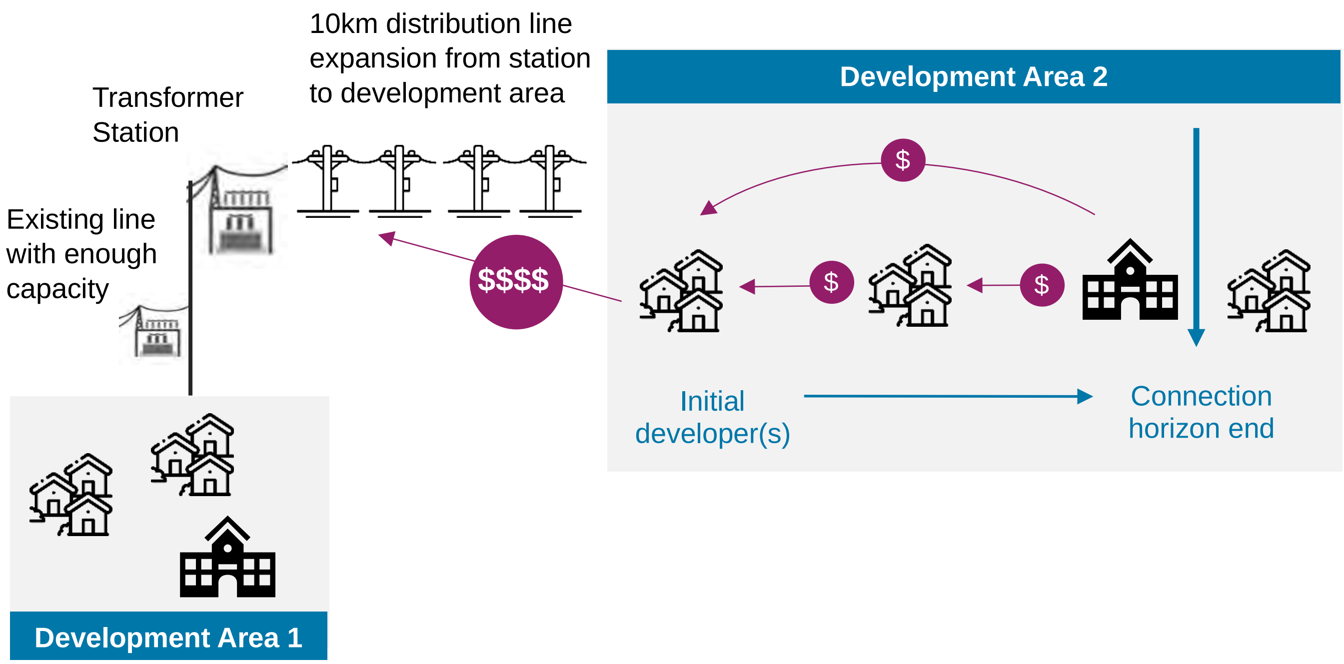
- Current Cost Recovery Framework & Greenfield Developments
- Growth and Ratepayer Costs
- Clarity regarding Current Rules
- Alignment of Planning

## 2.1 Current Cost Recovery Framework & Greenfield Developments

Most developers are concerned with large, multi-phase greenfield developments, where existing electrical infrastructure is several kilometers away from the development area. These developments often require substantial initial investments to bring the electricity infrastructure to the development areas. In these cases, "first movers" – the initial developers in the area – often end up carrying a significant portion of these infrastructure costs. Most stakeholders, including developers, indicate that the existing cost recovery framework falls short in these specific circumstances.

The following diagram illustrates the issue developers have raised regarding the location of development areas in relation to existing electrical infrastructure. Development Area 1, situated adjacent to the existing distribution line, would not require substantial initial system expansion and the current provisions of the DSC work. In contrast, Development Area 2, located further away, would require the construction of a 10-kilometer distribution line to connect to the area, resulting in much higher capital contribution for this line expansion.

Furthermore, if the development area includes multiple developers, the initial developers who begin building homes in the early stages will bear the full cost of any line expansion to connect the new area of growth. While these first movers will eventually receive expansion rebates as more developers connect over the connection horizon, the initial capital contribution can pose a significant financial burden. Additionally, any customers who connect to the expansion after the connection horizon has ended are not required to contribute to these initial expansion costs.




**Developers**, particularly those working on large, multi-phased projects, highlighted the substantial financial burden they face due to the high initial costs required to establish electricity infrastructure. Some comments pointed out that the five-year connection horizon often results in them bearing a disproportionate share of these costs, as subsequent developers who connect after this period do not contribute to the initial investment.

Several developers proposed that distributors adopt an integrated system planning approach, aligning with the government's housing targets and municipal plans. They recommended classifying the system extensions to development areas as enhancements. Furthermore, they suggested that the costs of these enhancements be recovered through distribution rates, ensuring that the distribution system investment aligns with broader development goals and lowers the costs to connecting subdivisions. Several developers also raised the point that as “profit-making” businesses, distributors should be expected to develop plans to expand their systems to accommodate more customers. Developers, and the association representing them, urged for timely action to meet the government’s housing goals.

**Ratepayer groups** expressed mixed views on the issues faced by some developers. However, many have raised concerns about the potential impacts on existing ratepayers resulting from any policy changes. These stakeholders assert that the current principle of cost responsibility – beneficiary pays – should be maintained. They emphasize the importance of a balanced approach that protects existing ratepayers from undue financial burdens while still enabling necessary infrastructure development to support housing developments.

One ratepayer group did suggest that the current framework may put more financial burden on large greenfield development areas and suggested socializing a portion of the system expansion to help open new geographic areas to residential or commercial developments. This approach, suggested by the ratepayer group, could be implemented through a standardized connection charge with any costs related to an expansion above the standardized charge being collected not just from the connecting distributor's ratepayers, but from all distributors' ratepayers across a designated growth area. The stakeholder suggested this approach would recognize potential broader economic and social benefits from new large-scale development on the designated region.

**Distributors** all believed that the current framework performs well for most of new customer connections and developments. However, several agreed that it could be financially burdensome for "first contributors" in a development area that is several kilometers away from the distribution system. Distributors were generally supportive of exploring policy changes concerning the connection and revenue horizons, but they raised concerns about potential administrative challenges and financing risks associated with these changes. Distributors did not advocate for implementing alternatives before a full analysis of the implications for distributors on financing costs and capital budget implications, along with consideration of the administrative impacts. Most importantly, distributors emphasized that any change must consider the impacts on existing customers and be implemented in a consistent way to avoid issues between distributors and developers.

## 2.2 Growth and Ratepayer Costs

There was a robust consensus for an equitable cost-sharing approach to shield new developments from excessive financial burden while ensuring that existing ratepayers do not pay for something they will not benefit from. This common understanding aligns with the Minister's expectation to ensure that growth and ratepayer costs remain balanced.

**Developers** believed that additional avenues should be explored beyond the connection and revenue horizons, considering growth and ratepayer costs. Some recommend that the province conduct an economic and infrastructure delivery review based on, and in alignment with, the current provincial Growth Plan.[1] They believed that solutions to the challenges of electrifying new communities could be achieved while striking a balance between consumer protection and the long-term growth and sustainability of the energy sector. Some developers suggested exploring a wide range of policy instruments to tackle the challenges encountered in large development areas. These include government legislation and regulations, as well as bulk electricity system planning by the Independent Electricity System Operator (IESO).

**Ratepayer groups** were concerned about the cost implications of growth and the allocation of these costs among new customers and existing ratepayers. All emphasized the need for a fair and equitable cost-sharing model to prevent undue financial burdens on current ratepayers. One stakeholder noted that any changes to the horizons should be uniformly applied across all types of customer connections to avoid unfair subsidies. Overall, their primary feedback emphasized the importance of maintaining a balance between facilitating development and protecting current customers from excessive cost increases. One ratepayer group noted that, under the current cost recovery framework, it is more difficult to open up new geographic areas to residential or commercial development, because the first movers pay a high price to do so.

**Distributors** understood the need for growth, with most stressing a fair and equitable approach that prevents undue financial impact on existing customers. Some distributors noted that, while revising the connection and revenue horizons would be helpful, an increased focus on and attention to system enhancements is necessary going forward. Some other distributors are calling for flexibility, and targeted exemptions such as extending the connection horizon up to 10 years for large development areas. Further, any changes to cost allocation rules should ensure new developments contribute fairly to infrastructure costs without unduly burdening existing customers. One stakeholder noted that the impact on the cost of development needs to be considered as it may impact economic growth and housing targets. They also noted that the overall objectives of any policy determination should balance the need for rate-payer protection against the larger societal and economic objectives of the government, while also incenting smart and cost-effective planning and growth.

## 2.3 Need for Clarity Regarding the Current Rules

Stakeholders have expressed a strong desire for enhanced transparency and consistency regarding cost responsibility and infrastructure plans among distributors. This improvement would significantly aid in project planning and funding. Additionally, there appears to be a varied understanding among different stakeholders concerning the rules and definitions in the DSC.

[1] Government of Ontario. Building 1.5 million homes

**Developers** noted that the complexity and variability in the application of these rules can create confusion and uncertainty. One suggested that the OEB, in part of its report back to the Minister, identify evaluation criteria that clearly balance the interests of the many parties potentially affected by changes to cost responsibility and cost recovery.

**Ratepayer groups** strongly called for greater clarity and transparency in the current rules governing electricity distribution and cost recovery. They highlighted the complexity and occasional ambiguity of the existing regulations, which can lead to inconsistencies and misunderstandings. Ratepayer groups noted a specific area of concern, which is the differentiation between “enhancement” and “expansion” capital spending. They noted that these need clearer guidelines to ensure fair and accurate cost allocation.

**Distributors** also noted the need for clarity and guidance regarding the current rules. Some call for well-defined categories of developments and clear rules not only for residential homes, but also for multi-unit residential buildings and mixed-use properties. Other distributors called for clear information regarding the economic evaluation and expansion deposits to allow distributors to provide more appropriate forecasting incentives to developers. One distributor feels that more clarity is an imperative step towards building an understanding about cross-subsidization between connecting customers and the general rate base. Similar to ratepayer groups, distributors suggested reviewing and updating various sections of the DSC to ensure all parties have a consistent understanding of cost allocation principles and the implications of un-forecasted customers. This clarity is seen as essential for promoting fair and efficient development while protecting the interests of both new and existing ratepayers.

## 2.4 Alignment of Plans

Stakeholders called for better strategic planning and further alignment of municipal housing plans with distributor infrastructure plans, to ensure that the pace of infrastructure investment can meet the housing targets set out for the province and support the energy transition and electrification of Ontario. Several developers propose the government establish a broader collaboration with all key stakeholders in the province, including the Ministry of Municipal Affairs and Housing, to expedite a solution and better understand the impact of the electricity connection and planning framework in delivering on this critical government priority.

**Developers** have expressed the need for a system that is fair to all parties and offers predictability for the industry, aiding the provincial government in meeting its housing targets. One stakeholder specifically recommended the creation of a working group, including all key stakeholders such as the OEB, IESO, Ministry of Energy and the Ministry of Municipal Affairs and Housing, to expedite a solution and better understand the impact of the current electricity connection and planning framework in delivering on this critical government priority. A number of developers suggested that distributors should be required to coordinate planning with municipalities' Official Plans to ensure they are building infrastructure to meet future growth.

**Ratepayer groups** emphasized the importance of integrated planning to ensure that electricity infrastructure developments are coordinated with broader urban planning objectives. They believe this approach can reduce redundancies, enhance efficiency, and ultimately lead to cost savings and better service delivery. Some ratepayer groups advocate for leveraging modern technologies and integrated planning to better manage local demand and supply. They also noted that energy infrastructure development should be closely tied to municipal planning and growth forecasts, enabling a more responsive and adaptable electricity distribution system.

Some stakeholders emphasized the need for better alignment between municipal planning and electricity distribution system planning. They noted that early and ongoing interactions between municipalities and distributors can lead to more efficient infrastructure development. Ongoing alignment would allow municipalities to incorporate infrastructure costs into their growth plans and zoning decisions, potentially reducing overall costs and improving the efficiency of development projects. Additionally, some stakeholders suggested that better coordination between electricity and gas utilities could further enhance planning processes. This approach would help address potential concerns early, enabling more timely and cost-effective solutions.

**Distributors** noted that electrification and the energy transition are and will result in a material shift in demand, and the infrastructure necessary to supply that demand. Planning will require effective coordination among parties and agencies, including developers, municipalities and utilities among others. Developers are encouraged to work together, and to the extent possible form consortiums in specific regions to ease planning and administrative challenges, and to promote cost efficiencies.

## 2.5 Other Comments

Several stakeholders also commented on broader issues that relate to housing developments, including energy transition and electrification, concerns with connection processes, clarity on residential muti-unit buildings and challenges in rural areas.

Several stakeholders noted the importance of considering the energy transition and electrification in distributors' short- and long-term planning. One stakeholder stated that there would not be sufficient system capacity if all homes required electric vehicle charging stations. Another stakeholder noted that net zero plans can significantly reduce peak demand and highlighted the importance of promoting energy efficiency.

One stakeholder raised concerns regarding utilities' cost for preparing an estimate for the connection and noted that upfront costs could be as much as $100,000 to then find out the project was unaffordable.

Several developers noted concerns with the time that it takes for distributors to plan, design and construct expansions to connect developments, which makes it challenging to meet development timeframes. One developer association suggested that a new and improved, and upfront consultation and planning process, should be contemplated to address this within the current municipal development application approvals process. Concerns with the connection process were also raised in the work undertaken by PwC as noted in Part II, including issues regarding how distributors communicate with developers. Specifically, developers interviewed by PwC noted that project costs were significantly affected by process-related issues and delays, particularly challenges in obtaining timely information about system capacity and the progress of their projects from distributors.

In the context of condominium construction, developers expressed concerns regarding sales timelines. Among those concerns, the unpredictable duration of condominium construction has posed challenges for buyers which is leading to hesitancy for developers in proceeding with construction. These developers suggested these delays may mean the connection horizon is too short given the time it takes to complete unit sales.

# 3 CURRENT COST RECOVERY FRAMEWORK

The OEB's DSC outlines the minimum obligations that licensed electricity distributors must meet, including the detailed rules related to the connection cost responsibilities between customers and distributors. The guiding principle that underlies the allocation of the costs associated with distribution expansion and connection investments is "beneficiary pays," which means that persons who directly benefit from an infrastructure investment should pay the full cost of the investment. Costs should not be allocated to any consumer, distributor or generator that will not benefit from the investment. Chapter 3 of the DSC provides rules on cost responsibilities under three sections: Connections, expansions and enhancements.

- **Connections –** section 3.1 of the DSC relates to the connection assets that form the portion of the distribution system used to connect a customer to the existing main distribution system. It includes the assets between the point of connection on a distributor's main distribution system and the ownership demarcation point with that customer.

- **Expansions** – section 3.2 of the DSC specifies the rules and cost responsibilities for expansion work. It covers the modification or addition to the main distribution system in response to one or more requests for additional customer connections that otherwise could not be made (e.g. by increasing the length of the main distribution system). When a distributor must construct an expansion to connect customers, an economic evaluation will be performed to determine whether the project is economic based on future revenues, or if the customer will need to provide a capital contribution for the expansion work.

- **Enhancements** – enhancement work described in section 3.3 of the DSC is part of distributors' ongoing effort to plan and build the distribution system for reasonable load growth and improve system reliability. The cost of the enhancement work is expected to be paid for by the distributors and the main purpose of this work is to improve system operating characteristics or relieve system capacity constraints.

The overall structure of Chapter 3, including Appendix B, which specifies the methodologies and assumptions for an economic evaluation model, has been in place since 2000, when the DSC was first established. Since then, several amendments have been made to the DSC, which is further explained in subsequent sections of this Report.

## 3.1 Expansions and Economic Evaluation

### Expansions

Work is considered an expansion when a distributor must construct new facilities as part of its main distribution system or increase the capacity of existing distribution system facilities to be able to connect a specific customer or group of customers. When a distributor is preparing an offer to connect a customer that involves an expansion, it is required to perform an economic evaluation to determine the costs that the customer(s) will be required to pay for the expansion work (i.e., the capital contribution). Expansion work can include building or upgrading distribution lines or transformer stations.

### Economic Evaluation

The purpose of the economic evaluation is to assess the expansion project against the beneficiary pays principle and determine if the project is economic and would pay for itself. The use of the economic evaluation, as set out in Appendix B of the DSC, relies on a net present value (NPV) calculation to determine if the future revenue from the customer(s) will cover the capital cost and on-going maintenance costs of the expansion project.[2] A positive or zero NPV means the future revenues that the distributor will earn, through distribution rates from this specific customer, will cover the capital and projected operating costs over the entire revenue horizon. The two main pieces of information from the economic evaluation model are the amount of capital contribution and expansion deposit.

### Capital Contribution

A capital contribution is determined based on the shortfall between overall costs and revenues, calculated using the total capital costs of the expansion work, plus ongoing maintenance costs for the expansion, minus the forecasted revenues generated by the new customers. The capital contribution payment from customers allows the distributor to finance the necessary costs associated with constructing and maintaining distribution assets, ensuring these costs are not shifted to other ratepayers who do not benefit from the expansion.

Capital Contribution ➡ Capital Costs ➕ On-going operation & Maintenance Costs ➖ Forecasted Revenues

[2] Distribution System Code. Section 3.2.1

### Expansion deposit

When a capital contribution is required for an expansion, the customer is required to provide an expansion deposit to the distributor, and when a capital contribution is not required for the expansion, the distributor has the discretion to collect an expansion deposit from the customer. Expansion deposits are used to cover both the forecast risk and asset risk described below:

- **Forecast risk** is associated with the projected revenue for the expansion and if it will materialize as forecasted. Once the facilities are energized, the distributor will return the percentage of the expansion deposit on an annual basis, in proportion to the actual connections that materialized in that year (i.e., if 20% of the forecasted connections or demand materialized in that year, then the distributor shall return 20% of the expansion deposit to the customer). This annual calculation will be done for the duration of the entire connection horizon. If at the end of the customer connection horizon the forecasted connections have not materialized, the distributor is allowed to retain the remaining portion of the expansion deposit.

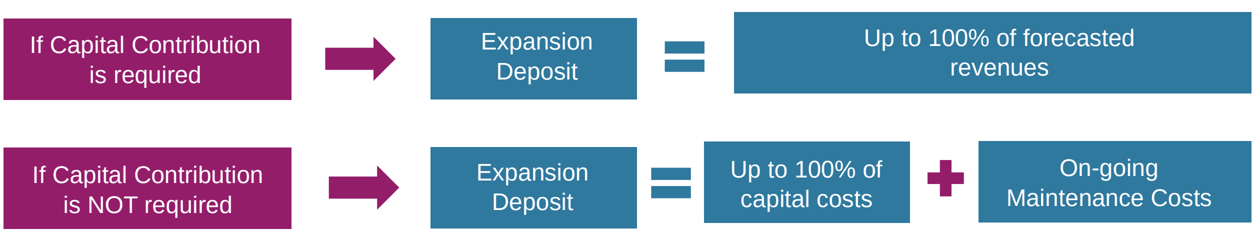
  **Example 3.1.1:** A developer initially plans for a subdivision of 400 homes to be connected, and an economic evaluation projects a shortfall of $100,000 between the costs and revenues from these homes. The developer pays a $100,000 capital contribution and provides a $300,000 expansion deposit to the distributor. Subsequently, the developer decides to reduce the number of homes to 200. By the end of the connection horizon, the distributor retains $150,000 from the expansion deposit. This adjustment compensates for the unrealized revenue originally included in the economic evaluation, which was used to determine the amount of the capital contribution.

- **Asset risk** is associated with ensuring that an expansion that is constructed by a customer under the Alternative Bid provisions of the DSC (see below) is completed to the distributor's required design and technical standards and specifications, and that the facilities operate properly when energized. When the alternative bid option is chosen, the distributor may retain at least 10% of the expansion deposit for a warranty period for at least two years after the last forecasted connection materializes, or after the end of the connection horizon. This portion of the expansion deposit can be applied to any work required to repair the expansion facilities within the two-year warranty period. The distributor will return any remaining portion of this part of the expansion deposit at the end of the two-year warranty period.

**Example 3.1.2:** A developer provides the distributor a $300,000 expansion deposit. The developer chooses to construct the expansion work by its own qualified contractor (i.e., developer chooses the alternative bid option). The distributor retains a $30,000 deposit for a warranty period and uses $10,000 to repair the expansion facilities constructed by the developer's contractor. By the end of the warranty period, the distributor will return $20,000 to the developer.

Distributors retain the discretion to determine the amount of the expansion deposit, as long as the deposit covers both forecast risk and asset risk. The maximum expansion deposit amount that a distributor can require from the customer is shown below:

- For expansions that require a capital contribution, the expansion deposit can be up to 100% of the present value of the forecasted revenues as described in Appendix B of the DSC.
- For expansions that do not require a capital contribution, the expansion deposit amount can be up to 100% of the present value of the projected capital costs and ongoing maintenance costs of the expansion project.[3]




## Related DSC Provisions

The DSC provides detailed provisions for other considerations related to expansion. For the purpose of this Report, the two relevant considerations are alternative bid and expansion rebate.

**Alternative bid** allows customers to hire their own qualified contractors to complete expansion work. This may be advantageous depending on individual circumstances providing potential benefits, such as reduced capital costs and shorter completion times

[3] Distribution System Code. Section 3.2.20

for the expansion. Upon transferring the completed expansion facilities to the distributor, the customer is compensated with a transfer price that is the lower of the cost to the customer to construct the expansion facilities, or the amount set out in the distributor's initial offer to do the work that is eligible for alternative bid. Managing this process can become complex if multiple customers are connecting to the same expansion facility as the transfer price that the distributor will pay to the customer(s) to cover the work completed under the alternative bid option may impact economic evaluation calculations for multiple customers. As mentioned earlier, if the expansion is completed under alternative bid option, the distributor will retain at least 10% of the expansion deposit for a warranty period of at least two years.[4]

**Expansion rebates** ensure initial customers that contributed to the cost of an expansion are compensated by customers who connect to the expansion facility during the connection horizon, but were not included in the forecast of customers for the economic evaluation. These unforecasted customers are required to pay their fair share of the costs of that expansion work that was paid by the initial customer(s). The initial customer(s) who paid for the expansion will be entitled to a rebate. The rebate calculation is based on the apportioned benefits allocated to each customer. These apportioned benefits are mainly based on the individual customer’s capacity needs.[5] Since only those customers connecting during the connection horizon are required to provide a capital contribution, the duration of this period is crucial to the rebate mechanism.

The expansion rebate is particularly relevant for subdivisions requiring distributors to construct main distribution facilities in the area, as these facilities are more likely to be shared by future customers. Within a subdivision, the likelihood of new customers emerging is relatively low.

## 3.2 Impact of Connection Horizon and Revenue on The Economic Evaluation

Both the connection horizon and revenue horizon play a part in determining the economics of expansion projects, and lead to the calculation of both the capital contribution and expansion deposit amounts. This section offers a high-level overview of how these two horizons are factored into the economic evaluation, and their impacts on the financial outcomes.

[4] Distribution System Code. Section 3.2.24
[5] Distribution System Code. Section 3.2.27

The connection horizon refers to the period during which the infrastructure is built, and customers are connected, while the revenue horizon looks at the timeframe over which the expected revenues from these connections will be realized. Both horizons are necessary in assessing the cost responsibility of an expansion, as they directly influence both the costs and revenues, ultimately affecting the determination of any necessary capital contribution and expansion deposit.

### Revenue horizon

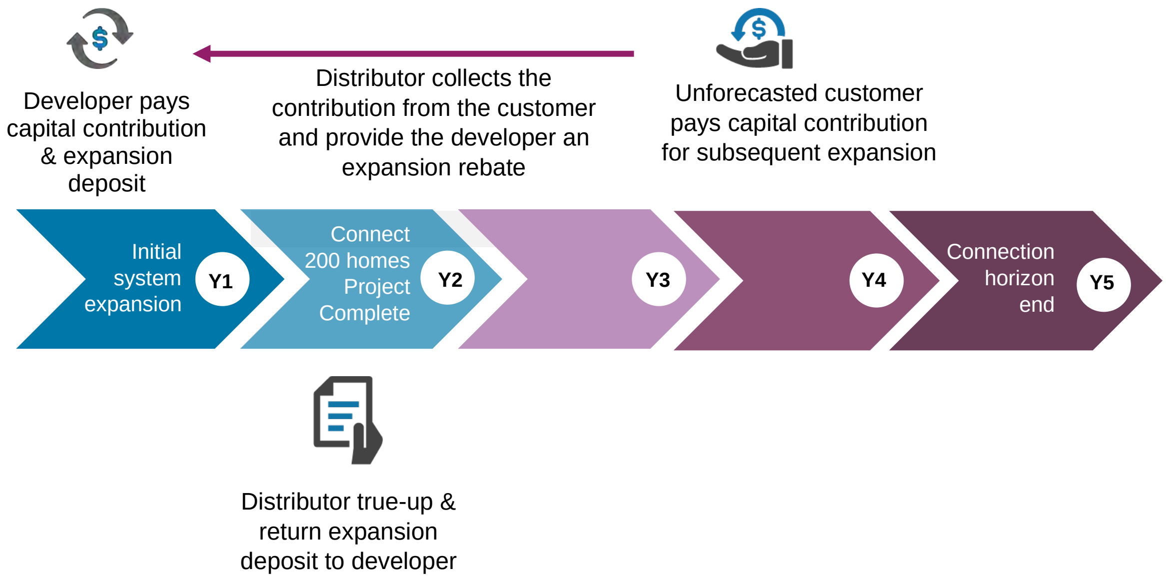
The revenue horizon is an input for revenue forecasting in an economic evaluation. A longer revenue horizon can lead to higher forecasted revenues, thereby reducing the shortfall between projected costs and revenues. Distributors have the discretion to set different revenue horizons for different customer types, which are to be assessed based on risk associated with the anticipated duration the customer is expected to remain connected. For instance, residential homes typically are assigned a 25-year horizon due to their expected longevity, while industrial customers, with greater risk due to potentially shorter operational spans, may have a 10-year horizon.

### Connection horizon

The DSC establishes a standard connection horizon of five years for all types of new connections. The DSC also provides distributors with the discretion to extend the five-year horizon on a case-by-case basis. The connection horizon serves several purposes: It provides both distributors and customers a timeframe to complete the connections and realize the projected load; it provides the basis for revenue calculations in economic evaluation; it sets a period during which distributors can perform true-up calculations; and it allows both forecasted and unforecasted customers to contribute to the expansion work. The impact of connection horizon can vary significantly across different connections. For instance, the effects might be minimal for projects involving a single customer where the connection is anticipated to be completed within the standard five-year period, as demonstrated in the example below.

**Example 3.2.1:** A developer is constructing a subdivision that will include a total of 200 homes over a span of two years.

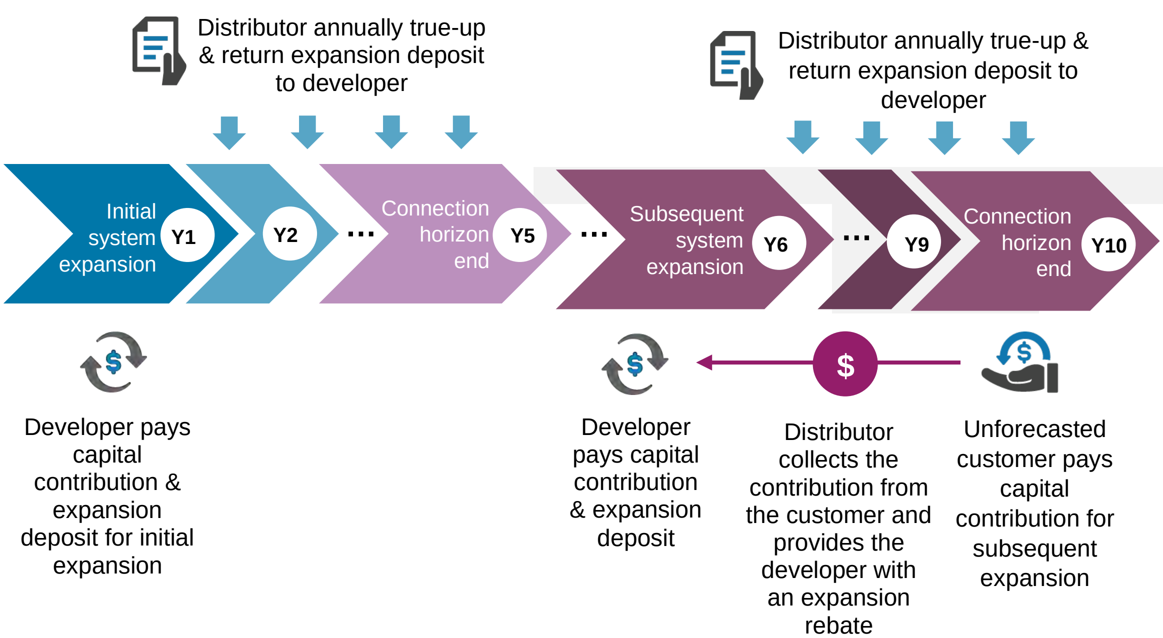
The economic evaluation for this project will include all capital costs, ongoing maintenance costs of the expansion, and forecasted revenues from these homes. Annually, the distributor will perform true-up calculations to reflect the actual number of homes connected and will adjust the expansion deposit returns accordingly. If the subdivision is connected according to plan without any deviations and the expansion is completed by the distributor (i.e., the alternative bid option was not chosen), the developer will be refunded 100% of the expansion deposit once all 200 homes are connected in year two. Over the next three years of the five-year connection horizon, if another customer connects to the same expansion, this new customer will contribute to the initial expansion and the initial developer will receive an expansion rebate. If there is no unforecasted customer within the connection horizon, there will be no need for additional calculations.




The impact of the connection horizon on a multi-phase connection can vary significantly, influenced by several factors, including the total duration and number of phases of the project, the accuracy of forecasted future load, the scope of expansion work needed to accommodate this load, and the number of future unforecasted customers that may connect to the same expansion. Each of these elements plays a crucial role in shaping the financial and logistical outcomes of the connection process. The following two scenarios demonstrate the potential impacts of different connection horizons on **multi-phase subdivision constructed by a single developer**.

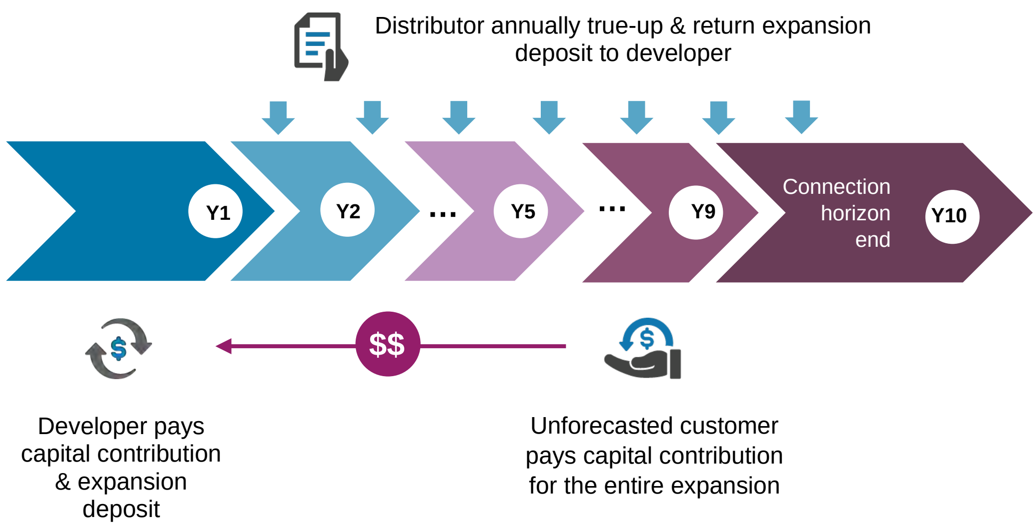
**Example 3.2.2** Scenario 1: A developer plans to build 2,000 homes over 10 years, and the distributor opts to segment the project into two separate phases — connecting 1,000 homes in the first five years and another 1,000 homes in the subsequent five years — conducting separate economic evaluations for each phase.

The first economic evaluation will account for all capital and ongoing maintenance costs, alongside projected revenues from 1,000 homes. The distributor will perform true-up calculations annually for the first five years to adjust for the actual number of homes connected and will accordingly adjust the expansion deposit returns. A similar approach will be taken for the second phase, initiated towards the end of the first phase. Under each phase, the developer will likely be required to make two capital contributions: The first in year one and a second around year five. If an unforecasted customer connects in year nine, this new customer is only required to contribute to the subsequent expansion costs and the developer will receive an expansion rebate only factoring the expansion work completed for phase 2.



**Example 3.2.3** Scenario 2: A developer plans to build 2,000 homes over 10 years, and the distributor decides to extend the connection horizon to 10 years to include the entire subdivision.

In this scenario, the distributor conducts a single economic evaluation and requires the developer to make a capital contribution for the entire subdivision in year one. The return period of the expansion deposit may be extended if the expansion is completed under the alternative bid option, with the warranty period beginning either when the last forecasted connection materializes or at the end of the 10-year connection horizon, whichever comes first.




The total capital contribution in Scenario 2 should closely align with the combined contributions from the two phases in Scenario 1. The differences arise:

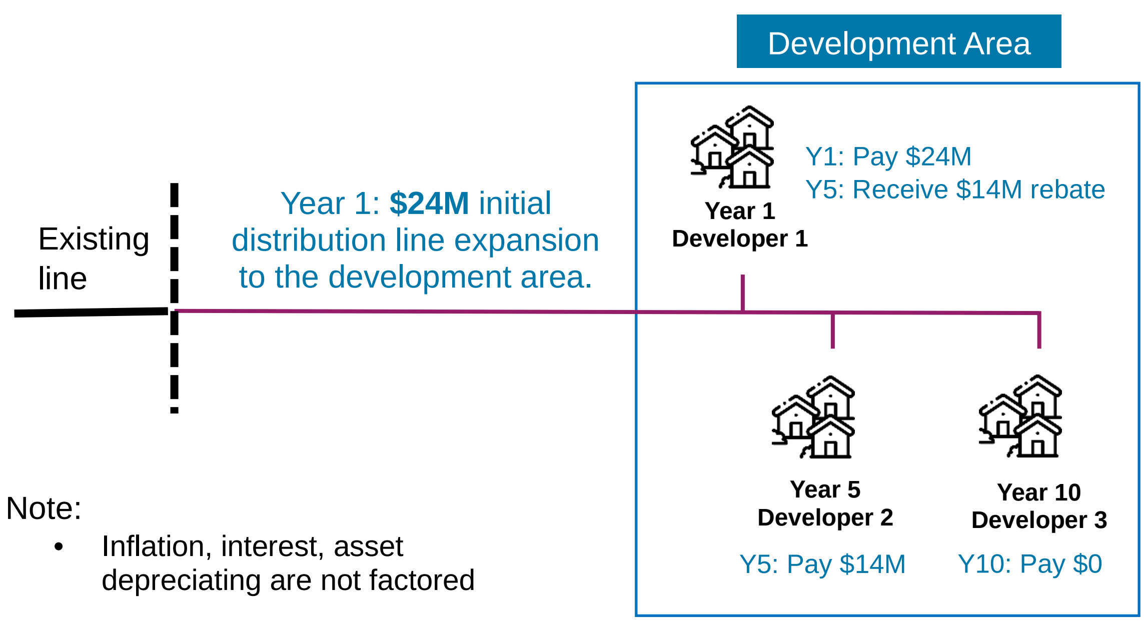
- When the connection horizon is extended, there is a higher likelihood that unforecasted customers will connect and contribute to the expansion. This provides the initial contributors a higher likelihood of receiving expansion rebates and thus reducing their costs to connect.
- Due to less precise estimation of costs and revenues in Scenario 2 (i.e., forecasting capital and ongoing maintenance costs and distribution rates over a longer period).
- From the effect of the time value of money (considering factors like inflation and interest).

The impacts of the connection horizon on a multi-phase, multi-customer connection introduce an added layer of complexity. If all customers are connected simultaneously, the distributor may attribute the expansion costs among them on a pro-rata basis. This attribution considers the apportioned benefits to each customer, factoring in variables such as each customer's non-coincident incremental peak load requirements, and their respective share of the total line length compared to the overall length being shared by all customers.

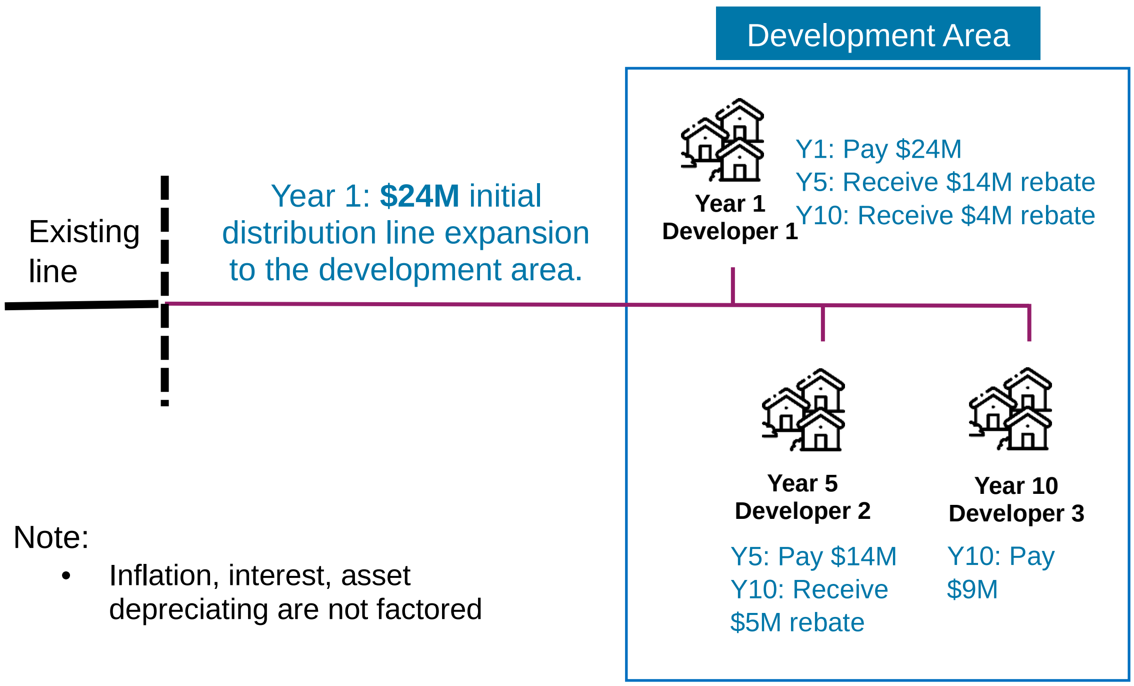
The following example demonstrates the potential impacts of the connection horizon on multi-phase subdivisions constructed by different developers.

**Example 3.2.4:** Three developers are planning to construct multi-phased subdivisions in the same area. The initial line expansion costs $24M. Developer 1 plans to build homes in year one, Developer 2 plans to build homes in year five and Developer 3 plans to build homes in year 10.

If the connection horizon is set for five years, the distributor will apply a similar approach to that described in Example 3.2.1 for Developer 1. When Developer 2 starts to build homes in year five, the distributor will perform economic evaluations for both Developer 1 & 2 and collect a contribution from Developer 2 for the initial line expansion and provide a rebate to Developer 1. Developer 3 connects in year 10 and will not be required to contribute to the initial line expansion (illustrated below).




If the connection horizon is extended to 10 years, Developer 3 will be required to contribute to the initial expansion constructed for Developer 1. This contribution will be made by Developer 3 and both Developer 1 and 2 will receive an expansion rebate (illustrated below).




## 3.3 Enhancements

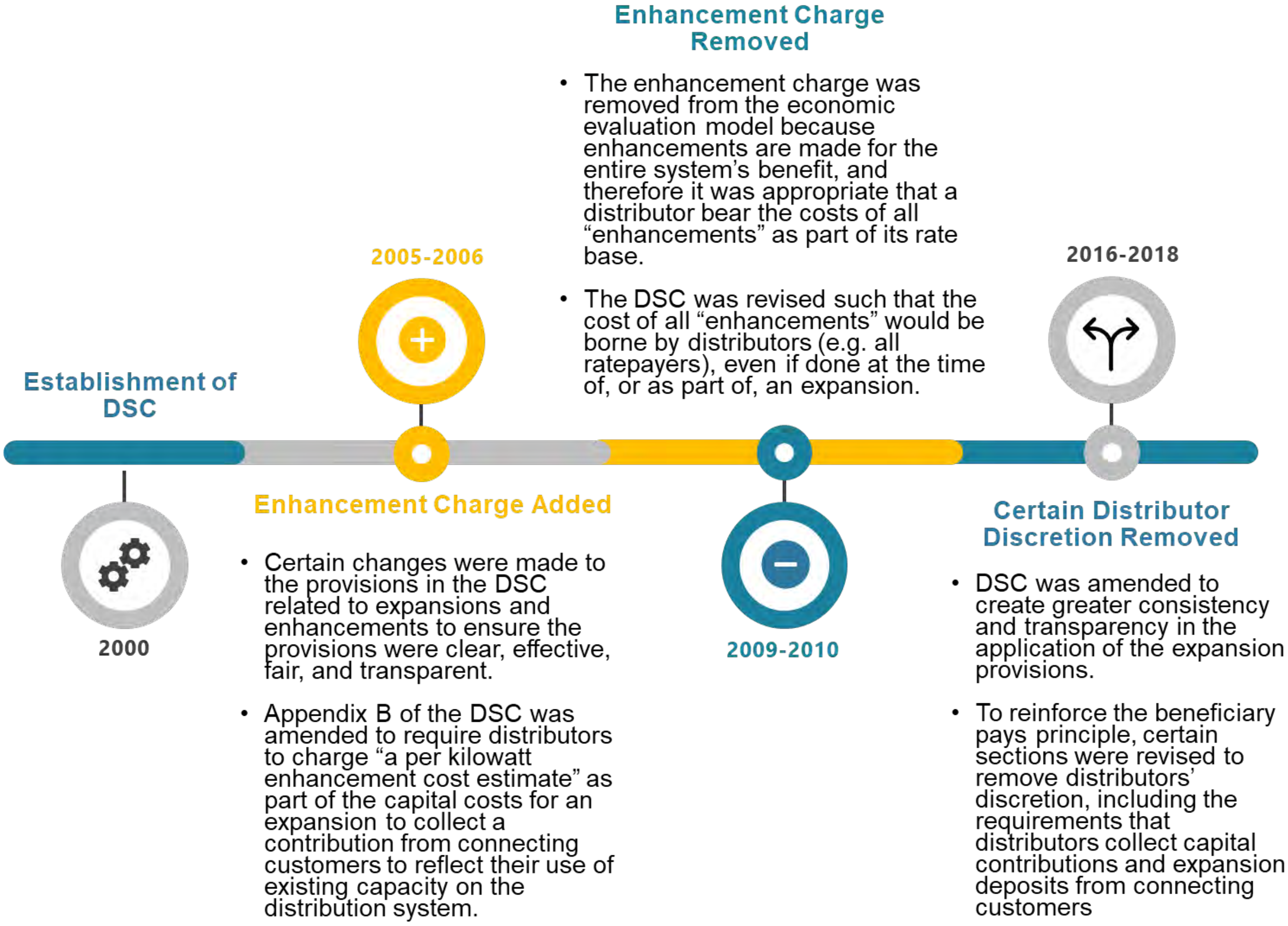
The DSC requires distributors to plan and develop the distribution system in anticipation of future load growth. This includes undertaking enhancements designed to improve the system's operational characteristics or alleviate capacity constraints. When considering these enhancements, distributors are required to consider the following:

(a) good utility practice;
(b) improvement of the system to either meet or maintain required performance-based indices;
(c) current levels of customer service and reliability and potential improvement from the enhancement; and
(d) costs to customers associated with distribution reliability and potential improvement from the enhancement.

Enhancements provide widespread benefits to the distribution system, rather than being limited to specific individuals or groups. Therefore, in terms of financial responsibility, distributors are required to cover the costs associated with constructing enhancements. As such, they shall not request any capital contributions from customers for the construction of enhancements.

## 3.4 The History of Key Changes Made to the Expansion & Enhancement

The following diagram provides an overview of the key changes made to the DSC provisions related to expansions and enhancements. Although these provisions have undergone numerous amendments over time, the fundamental principle remains unchanged – **those who benefit from an investment are responsible for its costs**. The DSC outlines general requirements regarding the financial responsibilities associated with all customer connections.




## 3.5 Cost Recovery Approaches in Other Provinces

The OEB also completed a preliminary review of the cost recovery approaches employed in two other provinces: Alberta and British Columbia.

## Alberta

In Alberta, the Alberta Utilities Commission (AUC) allows distributors to invest in new residential customer connections up to a prescribed maximum amount ($3,016 per residential lot with 100-amp service), referred to as the maximum investment level (MIL). The MIL is the maximum dollar amount that a distribution utility can invest in a new customer service connection and include in its rate base and recovers the investment over time through the rates it charges to customers. Any costs related to expanding the distribution system and connecting customers beyond the MIL are borne directly by the new connecting customer, rather than being socialized across customers through rates.[6]

## British Columbia

British Columbia  Hydro's (BC Hydro) services and pricing are regulated and approved by the British Columbia Utilities Commission (BCUC). Their Electric Tariff[7] details the electrical system Extension Policy, which outlines both BC Hydro's and the customers' responsibilities when a distribution extension is necessary to accommodate new or increased load demands. Under this policy, BC Hydro contributes to the connection costs in recognition of the anticipated additional revenue from the new or expanded load. For instance, BC Hydro offers a contribution of $1,475 for each added single-family dwelling, and $200 per kilowatt for the estimated billed demand from a commercial customer under the General Service Rate. Additionally, BC Hydro provides refunds on extension fees to the initial customer – the one whose project first necessitates the upgrades – if new customers connect to the same extension within five years.

Both Alberta and BC Hydro's connection cost recovery frameworks appear to be similar to Ontario's, in that the distributors contribute to the customer connections, in recognition of the anticipated additional revenue from the new or expanded load. Both jurisdictions follow the beneficiary pays principle to ensure that existing ratepayers are not impacted by the new or expanded load. In both the other jurisdictions the amount that is rate based is a fixed amount, while the approach under the DSC is to include in rate base the entire amount of the forecast revenues from the connecting customers.

[6] file:///C:/Users/GuoHe/Downloads/27658_X%5b%5d_27658-D02-2023 Residential Standards of Service and MILs - Phase 2_000224 (1).pdfAlberta Utilities Commission. Residential Standards of Service and Maximum Investment Levels – Phase 2 October 18, 2023.
[7] BC Hydro Electric Tariff

# 4 CONNECTION HORIZON

## 4.1 Current Policy

The current connection horizon policy specifies that the standard connection spans five years, calculated from the energization date of the facilities. Additionally, the DSC grants the distributor the discretion to extend this horizon on a case-by-case basis. If this is the case, a distributor must explain this to the OEB.

The five-year connection horizon aims to balance the needs of distributors, new customers, developers and existing ratepayers. Based on past connections, most customers, apart from those in multi-phase subdivisions, are connected within the first two years. Understanding these nuances has led to the selection of a five-year connection horizon. The connection horizon has three significant impacts:

- Changes in the connection horizon duration may increase the potential revenues as more customers are connected, which in turn may affect the anticipated dollar values for capital contributions and expansion deposits for subdivision connections.
- The length of the connection horizon affects the process for refunding of expansion deposits.
- The increase in potential for unforecasted customers to connect to the expansion facilities must contribute to the cost and will create additional rebates to the initial contributors.

## 4.2 Stakeholder Feedback

Many stakeholders indicated the current DSC provisions including the five-year horizon, were appropriate and worked well for most new connections or developments. Most stakeholders expressed the view that extending the connection horizon may be a reasonable change, but would require analysis for the impacts on distributors and existing customers. A number of stakeholders noted that extending the connection horizon itself would not fully address some developers' concerns regarding the greenfield multi-phase developments, as the extension does not remove the requirement for the first developer(s) to pay for the initial system expansion.

**Ratepayer Groups** emphasized the importance of ensuring that costs, whether direct or in terms of risk allocation, are not shifted from new customers (such as developers) to existing customers due to any changes in the connection horizon. Some are concerned about the risk of a development not proceeding as planned. These groups cited the Minister's Letter, emphasizing the expectation that in evaluating horizons and potential policy adjustments, the OEB should prioritize the protection of existing customers. One ratepayer group suggested that the OEB thoroughly investigate the impacts of maintaining or extending the horizon, assessing the effects on rate impacts, and incorporating best practices from similar jurisdictions prior to any policy changes.

These stakeholders believe that extending the connection horizon could enable more phased and financially manageable development projects. This extension would synchronize cost recovery with actual usage and the benefits derived from the infrastructure. Taking a uniform approach like this could streamline regulatory processes, offering clarity and predictability for developers and investors. One ratepayer stakeholder expressed support for extending the connection horizon if the extension is also applied to commercial and industrial businesses.

Despite some support for extending the connection horizon, some stakeholders in this group noted the potential risk of placing an increased financial burden on existing ratepayers through this approach. This includes the challenge of striking a balance between upfront costs and long-term benefits. Additionally, other ratepayer stakeholders cautioned that flexibility is essential to accommodate the unique circumstances of different regions and projects.

**Developers** all voiced concerns about the current five-year connection horizon, particularly noting its impact on large subdivision developments. They noted that this constraint on the economic evaluations negatively affects them by excluding any homes constructed after this timeframe from the calculations, which in turn reduces total revenue projections. A consensus among most of the developers was to extend the horizon to at least 10 years, and possibly up to 15 years, to better match the complete build-out period of a community.

However, these stakeholders also indicated that these specific proposed changes alone would not address the challenge of the significant upfront capital contribution required for the initial expansion work for greenfield subdivisions. Since this phase often entails the most substantial expenses, first mover developers face a higher financial burden compared to subsequent phases. They suggested that there needs to be greater recognition of longer periods required for large new developments, which require significant expansions to connect to the existing electricity system. And while they acknowledge discretion for distributors to extend the horizon, they have not seen this discretion exercised in the past.

Developers also expressed concerns about the inequity of the five-year connection horizon where customers connecting to the expansion after the fifth year do not contribute to the capital costs of the initial expansion. Many developers believe that extending the connection horizon and allowing these later-connecting customers to contribute would ensure fairness in funding the costs of growth and would reducesthe “first-mover” disadvantage without unfairly burdening other customers.

**Distributors** all agreed the current connection horizon works in most cases. Most distributors indicated that if the OEB were to decide to extend the connection horizon, that an extension to a maximum of 10 years could be manageable and may better accommodate longer-term developments. Several distributors commented that any change should be standardized for consistent implementation across the province to provide developers with greater certainty and minimize disputes. Some distributors suggested there was no need to make any change as long as the distributor's discretion was maintained. Some others suggested that any change should focus on ways to capture more of the unforecasted connections. At least one association strongly endorsed not making a general change but continuing the discretion of distributors to extend the connection horizon. Another association noted that extending the connection horizon to all expansions was not practical or feasible and would not address the concerns raised by developers. The association recommended a targeted change to the connection horizon to address these specific scenarios that occurred in greenfield developments.

Distributors also noted that extensions to the connection horizon could create additional administrative burdens. If the horizon were extended, distributors would need more resources to track, analyze, rebate, and hold connections to account. Increasing the connection horizon would become very complex as infrastructure is built and would establish significant asset utilization risks that have the potential to create intergenerational rate impacts. Distributors were also concerned that by mixing various capital investments, from smaller subdivisions to major infrastructure projects that require significant initial system expansion, this would introduce a level of complexity in managing financial contributions over time. This complexity could escalate disputes and disagreements among customers, potentially leading to more conflicts.
Therefore, a targeted change to the connection horizon to address specific scenarios that have occurred in greenfield developments was recommended.

Distributors noted that extensions to the connection horizon could also impact their financing costs; and capital budgets, and disincentivize growth. Since longer horizons increase the likelihood of "expansion deposits only" situations, wherein the connection costs are essentially treated as a day-one utility expense, distributors could see higher net expenditures if extensions become standard practice. Distributors highlighted that the OEB will need to be ready to adjust capital budgets and support increased funding requirements to enable distributors to finance the expansions. Additionally, they highlighted the likelihood of upward pressure on rates for customers, which must be managed in line with the Minister's expectation that any changes maintain fairness and affordability. Distributors suggested a transition period for implementing any policy changes allowing for consideration of the financing and capital budget impacts.

Distributors have expressed a need for clarity regarding the potential impact of an extension on other aspects of the DSC, such as unforecasted customers, refunds and deposits. Distributors also noted that there are potential issues in the current approach to utility discretion surrounding connection horizons. When applied inconsistently and without a clear set of principles, there is a risk of treating customers unfairly and randomly. Consequently, distributors have indicated that if the OEB were to proceed to extend horizons, clear direction would be needed on how other affected sections of the DSC should be implemented. All distributors emphasized that establishing consistent rules that recognize the unique needs of different development projects based on their specific circumstances would be a more equitable system. Consistency, in their opinion, will support efficient housing development by not causing developers to make their decisions about which distributors' service areas to build in based on a particular distributor's approach to extending the connection horizon.

## 4.3 OEB'S Recommended Actions

After reviewing stakeholder feedback, the OEB recognizes the need for changes to the existing rules to improve clarity and consistency concerning distributors' discretion to extend the connection horizon. It is also apparent that for multi-customer, multi-phase subdivision connections, there is a need for additional rules to alleviate financial burdens on initial developers and to reduce administrative burdens on distributors when extending the horizon. This approach of targeted changes to the rules recognizes stakeholders generally agree that the current cost recovery framework is effective for most other types of connections. Consequently, the OEB recommends:

1. Amending the DSC to provide clarity on distributors' discretion to extend connection horizon for specific circumstances.
2. Amending the DSC to provide clarity regarding the process and requirements when the horizon is extended.
3. Establishing a capacity allocation model that considers multi-customer, multi-year projects.

**Amend the DSC to provide clarity on distributors' discretion to extend a connection horizon for specific cirucmstances**

The OEB recommends that it proceed with proposing amendments to the DSC to provide clarity on when a distributor should consider extending the horizon. While the DSC has always provided distributors with discretion to extend the horizon, this power is infrequently utilized. The proposed changes to the DSC would provide clarity and detailed guidance to distributors on the circumstances under which the horizon can be extended beyond five years. Distributors will be expected to carefully assess the reasons for not granting an extension when a developer or customer requests one. To support this expectation, the OEB will provide clarity on when such extensions can be granted to minimize disputes and encourage consistency in the treatment of developments across the province. Continuing the provisions for use of discretion ensures that each case is evaluated on its individual merits, preventing unnecessary extensions for projects where connections are expected to be completed quickly and could delay release of deposits or refunds. This approach helps avoid imposing additional administrative burdens on distributors without offering any tangible benefits to these connections.

By providing a good understanding of the existing rules and clarity to distributors' use of their discretion, the OEB expects this approach will facilitate a prompt response to developers' concerns given the urgency to act on the government's housing development priorities. These changes to the DSC will ensure that a greater number of customers are included when determining capital contribution amounts. Applying an extended horizon also addresses the concerns about unforecasted customers and allows more unforecasted customers to contribute to the initial expansions.

**Amend the DSC to provide clarity regarding the process and requirements when the horizon is extended.**

As noted by some distributors, the DSC provisions regarding expansions are not entirely clear in terms of their operation when a distributor applies its discretion to extend the connection horizon. To address these concerns, the OEB recommends amending the DSC to provide detailed guidance related to an extension, including capital contributions, expansion deposits and expansion rebates when the horizon is extended.

Where a connection horizon is extended, allowing for an extended period for more forecasted and unforecasted customers to contribute to the expansion, the OEB expects that the expansion deposit period would also be extended to align with the end of the horizon. To increase the number of forecasted connections, distributors may need to obtain commitment from the developer regarding the future phases, in the form of contracts or expansion deposits. This approach will be maintained through the current method for setting expansion deposits, where developers provide security to distributors for the portion of the project's costs not covered by the capital contribution. For unforecasted customers, the existing rules regarding expansion rebates would also be utilized for the entire extended horizon. To address distributors' concerns regarding the administrative burdens, additional guidance will be provided regarding when and how distributors are expected to recalculate the capital contributions, expansion deposits and rebates throughout the extended horizon period.

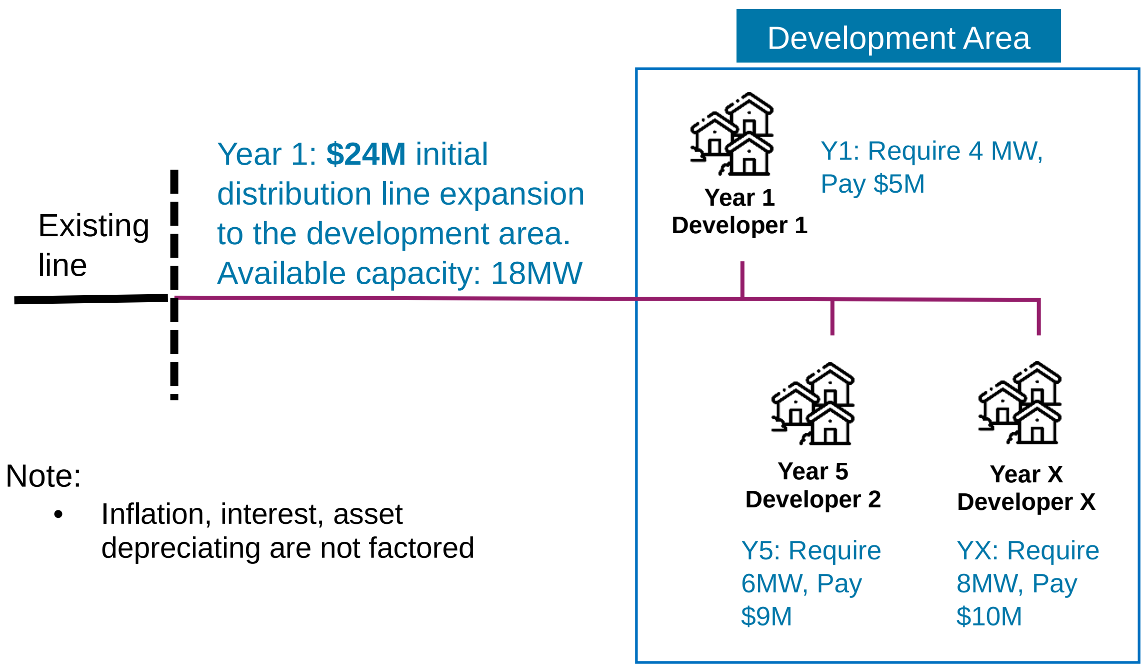
In response to concerns about the impact of upfront financing requirements, the proposed amendments will establish the distributor's ability to recover a capital contribution over time, rather than upfront. This approach will provide more financial flexibility to the developers and align the contributions with the new connections when they come into service.

**Establish a capacity allocation model (CAM) that considers multi-customer, multi-year projects**

As noted by most stakeholders, extending the connection horizon itself would not remove the significant financial burdens faced by initial developers. Therefore, the OEB recommends the development of a capacity allocation model that will enable distributors to plan appropriately sized expansions for new development areas that involve multiple developers and/or customers and span several years.

This CAM will ensure that developers who connect first pay a fair share of the costs, while those who connect later will contribute based on their allocated share of the new facilities. This proposal is similar to Enbridge Gas Inc.'s Hourly Allocation Factor (HAF), an approach recommended in several stakeholder submissions as a viable model for the electricity sector. The current DSC mandates that a distributor allocate the costs of distribution facilities among multiple customers based on the apportioned benefit. However, what is not addressed is how such an allocation would function in scenarios where there is an extended connection horizon and potentially several years between connections by different customers/developers.

Under the CAM, when multiple developers are involved over an extended period, all will be part of the extended connection horizon. The initial developers will cover the capital costs proportionate to their capacity needs. Subsequent developers connecting during the horizon will also contribute towards the expansion based on their individual capacity requirements (as illustrated below). This approach is expected to mitigate the risk of constructing multiple new or replacement facilities as each new development reaches the connection stage of its construction. It also enables distributors to shift from short-term to long-term, strategic planning. The existing rules regarding unforecasted customers and expansion rebate will remain, with adjustments as needed to suit the extended horizon and the capacity allocation model.




These changes are expected to reduce the upfront capital contribution by first movers by spreading it across an increased number of connections anticipated over a longer horizon. The modifications are designed to maintain the existing risk and cost allocation between new and existing customers as closely as possible.

**Implementation Considerations**

The OEB believes that enhancing the clarity of the connection horizon extension and introducing a CAM will efficiently address the challenges of large greenfield developments, offering a more effective solution than developing entirely new rules, which would require extensive stakeholder consultation and lead to delays in connecting new subdivisions. These changes aim to mitigate the capital contribution required for a project by considering the increase in customers resulting from a longer horizon. This increase in customers is expected to reduce the capital contribution amount needed from each customer. The changes will be developed to maintain as closely as possible the current risk allocation between new and existing customers.

For multi-phase developments involving a single developer, some stakeholders contend that capital contributions could be substantially lower because the inclusion of more homes would yield higher revenues in the economic evaluation. The OEB intends to examine these circumstances thoroughly as part of its proposed amendments to the DSC.

Implementing a CAM will necessitate the development of rules to guide the process of identifying when a CAM may be used and how it should be administered. For instance, like Enbridge Gas's HAF, the utility may need a significant portion of forecasted customers to sign contracts obligating them to contribute to the facility when they connect.

As noted earlier, the duration of the horizon extension impacts capital contributions and deposits. Once the horizon is extended, the capital contribution and deposits will need to be recalculated to reflect this extension. As the OEB refines these provisions to enhance clarity and develop the CAM, it is crucial to identify strategies to minimize the administrative burden this process may entail. Nevertheless, the OEB maintains that while administrative efficiency is important, it should not hinder the fair treatment of new customers or impede the achievement of the province's housing objectives.

Regarding financing issues raised by the distributors and ratepayers, the OEB is currently reviewing its approach to all rate-regulated utilities' financing in its Cost of Capital Review proceeding. That proceeding will consider the financing arrangements and the means of accessing debt and equity financing to support utilities' operations. The OEB recognizes that its recommended changes, including the CAM, would lead to decreases in initial capital contributions, thus increasing the upfront amount that distributors are paying towards the expansion projects. As a consequence, these increased upfront costs would need to be financed as part of capital budgets. This may necessitate the OEB addressing changes in distributors' capital needs through existing mechanisms such as the Incremental Capital Module and Advanced Capital Module, particularly in cases where distributors are not planning a Cost of Service application to rebase their rates.

Developing any new rules and associated guidance to support greater use of the discretion to extend a connection horizon and the CAM will necessitate consultation and formal DSC amendment processes. However, providing clarity on the rules related to an extension should not require many changes. The rules for the new CAM can draw heavily from the already considered and approved HAF, as well as the input gained through this consultation. The next steps involve preparing proposals for discussion with the sector.

Initially, these changes will prioritize housing connections in line with the province’s priorities, as there is expected to be less modification needed in the DSC related to these types of developments. However, changes will also be available for use in the case of other customer connections, such as schools and commercial customers connecting in the same development area.

# 5 REVENUE HORIZON

## 5.1 Current Policy

The DSC sets the maximum customer revenue horizon of 25 years, calculated from the in-service date of the new customers. Given the economic evaluation model uses discounted cash flow calculations, both revenue and O&M cost forecasts are impacted by the discount rate – the longer the time horizon, the greater the influence of the discount rate will be on the NPV.

## 5.2 Stakeholder Feedback

Many stakeholders support extending the revenue horizon to 40 years for residential subdivision connections, given that houses typically exceed the current 25-year horizon with lifespans often spanning 50 years or more. A 40-year horizon is also seen to align more closely with the average lifespan of distribution assets serving residential customers.

Very few **ratepayer groups** commented on the revenue horizon, and largely relied on the general concerns and comments related to impacts on existing customers and the importance of the beneficiary pays principle. Ratepayer groups that provided comments noted while extending the horizon reduces developers' upfront contributions, this could result in rates impacting existing customers, including residential, low-income, commercial and industrial customers. One ratepayer group noted that to decide on an extension of the revenue horizon, it is necessary to know the impact of that extension on existing residential and lower-income ratepayers. They suggested the OEB perform further analysis to understand the current situation regarding revenue horizon and the impacts of extending the horizon out to 40 years. The analysis should consider different scenarios that illustrate the rate impacts and benefits to existing residential and lower-income ratepayers, as well as to the residential ratepayers in the new community and/or subdivision.

**Developers** were supportive of extending the revenue horizon to 40 or even 50 years, as this would better align the economic evaluation period with the depreciable life of electricity distribution assets, as well as the expected lifespan of residential homes. They also pointed out that extending the horizon, while helpful, does not completely solve the problems faced by developers of greenfield multi-phase subdivisions. Extending the revenue horizon merely reduces the amount of this initial capital contribution. Overall, developers viewed this as a positive step toward a comprehensive solution and advocate for continued dialogue.

**Distributors** were either supportive or open to extending the revenue horizon as a measure to reduce housing costs, as it does not surpass the average asset life that is included in the economic evaluation. They noted that the revenue horizon should be closely matched to the expected life of the assets being used to service the expansion area. Some distributors also acknowledged that the extension alone will not resolve the “first mover” issue.

Some distributors noted that the risk to ratepayers in extending the revenue horizon for residential housing development is minimal given residences are expected to remain connected. However, they cautioned against extending it beyond distribution asset life due to the potential for higher future replacement costs to be included in the economic evaluation. One distributor noted that there is sometimes a difference in the revenue certainty associated with different types of expansion projects. For example, for a residential subdivision with many smaller and similar loads, the risk of load not materializing as expected is fairly low. Conversely, projects that forecast large, lumpy, or singular loads contain a greater risk that it may not materialize as expected. The distributor noted that the OEB may wish to consider tying the revenue horizon to the type of load being connected.

Some distributors noted that changes to the revenue horizon will impact distributors’ capital budgets and the amount of funding necessary through rates if a smaller capital contribution is made by the developer, as well as the increased financing related to a longer revenue horizon.

Most distributors recommend that the extension of revenue horizon should be limited to residential developments only. One distributor noted that only individually metered/billed residential customers should qualify for a longer revenue horizon.

## 5.3 OEB’s Recommended Actions

The OEB is of the view that extending the revenue horizon to 40 years is a reasonable step to ensure a balance between existing and new customers and given that residential homes are expected to stay connected. It is important to note that the extension will not exceed 40 years, as longer durations will increase the likelihood of new capital costs for replacing assets, and a longer extension will have a diminished impact on the distributor’s forecasted revenues in the economic evaluation due to the effect of discount rates. The change to the revenue horizon will reduce the shortfall between costs and revenue in the economic evaluation, and lead to reduced expansion costs for customers like subdivision developers.

This extension of the horizon aims to provide a more balanced cost allocation framework as it tries to reduce the financial burden on developers while not burdening the existing ratepayers. While extending the horizon may lead to increased forecasted revenue, the present value does not increase proportionally due to the compounding effect of the discount rate, potentially limiting any decrease in developers' capital contribution.

Amendments to the DSC to extend the horizon, as with the changes to the connection horizon discussed above, are far more likely to be implemented in a timely way to address the urgency for action identified by developers and in the Minister's letter. These amendments would maintain the principles underlying the DSC expansion provisions and avoid introducing new rules that may cause delays in implementation or questions about impacts on existing projects. The revenue horizon extension related amendments will be targeted to:

- Primarily housing connections, aligning with the province's priorities, and anticipating minimal modifications to the DSC concerning these developments.
- Multiple developers as part of an allocation of new capacity from an expansion removing the initial first mover's responsibility to fund the entire expansion.

The OEB acknowledges the views of distributors that any adjustments to the economic evaluation resulting in decreased capital contributions will require distributors to finance a larger portion of expansion projects through their capital budgets. The longer period resulting from the extension will require distributors to finance the longer payback period as opposed to having the capital contribution upfront, meaning potential pressures on their borrowing and the need to manage overall infrastructure costs if funding is tighter. As noted in the prior section, the OEB is currently undergoing a review of its Cost of Capital policy and the financing mechanisms that distributors can employ. Distributors preparing for rebasing will need to accurately forecast new developments to ensure they can offset construction costs for their capital budgeting at the next rate filing. Consequently, the OEB may need to address changes in distributors' capital requirements through established mechanisms like the Cost of Service, Incremental Capital Module and Advanced Capital Module.

# 6 ALTERNATIVE APPROACHES

In the Letter of Direction, the Minister asked the OEB to review potential models for cost recovery. In order to respond to this request, OEB staff identified three alternative cost recovery approaches to discuss at the stakeholder meeting: Redefining enhancements under the DSC; establishing development charges for the electricity sector; and setting standalone rates for development areas. These three alternatives were either raised through earlier discussions with stakeholders or are used in other sectors. Additionally, through the consultation, stakeholders suggested two other methods: Upstream charge and area wide growth charge.

Stakeholders all stressed in their comments the importance of conducting a thorough analysis of all alternative cost recovery approaches to evaluate their costs, benefits and impacts on ratepayers prior to any changes being contemplated. Any new approach must consider the impact on existing ratepayers to ensure the Minister's expectation that rates will remain affordable is met. The subsequent sections provide further details on each of the alternative approaches, stakeholder comments regarding these approaches, followed by the OEB's analysis and recommendations.

## 6.1 Redefining Enhancements

At the stakeholder meeting, stakeholders discussed the idea of redefining "enhancement" to include system expansions built to connect development areas to the existing electricity distribution system to support large, multi-year residential developments. The idea being that these types of investments provide broader benefits to the system through economic growth. Similar to all other enhancements, the costs for these enhancements would be recovered through distribution rates. All the subsequent expansions within the development areas would follow the DSC's cost recovery framework. This approach would reduce the initial expansion costs, thereby making it easier for developers to establish subdivisions in new development areas.

**Stakeholder Comments on Redefining Enhancements**

Developers and some distributors advocated for the introduction of a new approach to enhancements, with detailed criteria related to substantial infrastructure projects for connecting greenfield developments to existing infrastructure. Many developers noted that distributors should improve their planning approach by factoring in the load growth and developments that are already included in the municipality's Official Plan, and that costs for building out to new growth areas should be recovered through rates. One developer proposed that this type of new growth area expansion be categorized separately and that developers be charged only for their share of the new capacity and that benefits to the entire system be recognized. Another developer suggested the use of policy tools to require expansions to be partially funded by ratepayers above a specified cap on connection costs, similar to the approach used to enable renewable generation through distribution system expansions. The developer suggested further discussions would be necessary to determine which of these approaches might be worth pursuing.

Most of the ratepayer representatives and several distributors were opposed to any change that would expand the scope of enhancements. They are concerned that this would inappropriately shift the financial burden from new to existing ratepayers. These existing ratepayers would not receive any direct benefits from these enhancement projects, raising concerns about fairness and equity in cost allocation. In addition, distributors noted that creating a policy that is dependent on a project type could result in unequal treatment of developers in addition to different treatment of customers within a single rate class. There was also a concern that any attempt to expand the definition of enhancement would lead to unnecessary new facilities and risks of overbuilding.

**OEB Analysis on Redefining Enhancements**

Redefining enhancements to expand its application raises a number of important considerations as noted by the stakeholders, such as avoiding unnecessary expenditures by distributors and the related costs to ratepayers. The infrequent nature of certain scenarios requires a flexible approach to defining enhancements that accounts for the diverse operational contexts of different distributors.

One stakeholder highlighted the challenges in relying on municipal plans that are updated every 10 years, and often contain only high-level land use estimates. Distributors need a higher degree of certainty in their forecasts to construct their systems effectively and prevent unnecessary expansions. Depending solely on these municipal plans for initiating enhancement projects could result in inefficient planning and investment decisions, potentially exposing distributors to significant financial risks.

Distinguishing between greenfield and brownfield projects adds a significant layer of complexity, particularly when projects involve construction or upgrades in a mixed greenfield and brownfield area. It is also uncertain if the definitions of “greenfield” or “brownfield” areas can be clearly established and understood by all stakeholders. For instance, a large multi-phase development could span a substantial brownfield site or a combination of brownfield and greenfield sites, requiring significant upgrades to the distribution system to meet new capacity demands. Furthermore, the “first mover” challenge in these mixed-use areas often mirrors those found in pure greenfield developments. In contrast, if a multiphase greenfield development is situated near existing electrical infrastructure, developers may not face the same burden of funding substantial initial expansions.

The criteria for enhancements must also consider their applicability to various types of customer connections, such as multi-unit residential or commercial developments, and define what constitutes “multiple” in terms of developers, phases, or customers. It is also challenging to establish a one-size-fits-all threshold for projects, given the range of customer connection requirements that might be involved. For example, a subdivision development may require the construction of different distribution assets, such as building or upgrading distribution lines at various voltage levels, transformer stations, or a combination of these assets, complicating the criteria for what qualifies as an enhancement.

## 6.2 Fixed Development Charges

For the purpose of the stakeholder meeting, staff identified as a potential alternative the concept of Fixed Development Charges (FDC), derived from the development charge (DC) model used by municipalities to pay for infrastructure necessary to support growth. DCs are one-time fees levied by municipalities on all new residential and non-residential developments. The DC model relies on the principle that existing taxpayers should not be paying for new growth. The process of calculating DCs involves a municipal study that includes:

- Detailed projections of anticipated residential and non-residential growth;
- Identification of services needed to meet the demands of this growth; and
- Detailed forecasting of the capital costs for each required infrastructure project.

Once the charge is determined based on the study, municipalities are required to establish reserve funds for each service for which development charges are collected. These funds must be spent on the specific infrastructure projects they were intended to support. Charges are collected from the developer at the time the developer receives the permit to construct.

**Stakeholder Comments on FDC**

Developers expressed a need for a thorough review on FDCs to understand how all components would integrate. They raised concerns about potential unfairness due to the varying needs of different subdivisions. Averaging costs across a large geographical area could lead to unequal distribution of the burden. Thus, developers are of the view that introducing a development charge model alone would not be workable or be sustainable without the examination of a full cost recovery model.

In addition, developers argue that electricity distributors, as profit-making business, unlike municipalities, should create business plans to fund future growth through additional profits from housing expansions. They are concerned that FDCs would unfairly shift expansion costs onto homebuilders and future homeowners.

Distributors raised several important questions regarding the implementation of FDCs. They believe that FDC cost recovery framework helps mitigate the risks for first movers in multi-phase developments and protect existing customers from the costs of stranded assets or assets funded for long periods without new connections. Additionally, they were particularly interested in understanding how bulk metered residential buildings would be integrated into the FDC model, given that municipalities often have different development charges for various types of housing such as condos, rentals, single-family homes and townhouses.

Some distributors noted that FDCs might not align well with the beneficiary pays principle, raising concerns that larger projects could be inherently cross subsidized by smaller projects. This potential misalignment underscores the need for a careful examination of how FDCs would impact different types of developments and the overall fairness of the cost distribution.

One ratepayer representative saw the idea of development charges as an attractive option. If done correctly, the FDC will assign the immediate cost of new connections to those who benefit from the connections. They will also reduce the cost of new homes, benefiting all in the community. This consumer group envisions that as subdivision approvals are issued, an FDC would be levied and put toward the rate base to reduce it. Any amount above the standard FDC would be collected through rates, but in a mechanism that would share the costs across all distributors within a particular “growth area” of municipalities that would benefit socially and economically from the new greenfield project.

**OEB Analysis on FDC**

The OEB believes that the FDC cost recovery framework would be complicated to implement, and it will require an in-depth stakeholder consultation. If the OEB were to implement a FDC model as a one-time connection fee charged to new customers, such as developers, at the time of construction, the fee could be tiered based on the type of connections (e.g., residential homes, residential or commercial buildings, etc.) given the significant difference of work required for these different types of connections.

In order for a FDC model to be used in electricity, distributors would have to conduct the same type of study as municipalities with projections of anticipated residential and non-residential growth in its entire service area to accurately project future infrastructure needs, including new or upgraded distribution stations and lines. The results of this study would then inform the costs of the needed infrastructure and how these costs should be allocated among different types of customer connections, ultimately determining the unit costs for each connection type.

The process outlined above involves substantial effort from distributors, who must conduct detailed studies and propose a FDC for each connection type. This proposed FDC would need the OEB's review and approval, typically as part of the distributor's Cost of Service application, given the significant implications of the FDC. The timeframe required for distributors to finalize an FDC and secure funding for the account is likely to be out of sync with the government's timeline for meeting housing targets.

FDCs come with a rigid fee structure and the fees are calculated based on average costs, which will not efficiently reflect the varying costs of different types of developments, their sizes and locations. As a number of stakeholders noted, this could lead to unfairness, particularly for infill customers who may have to pay regardless of having an existing connection.

Additionally, the complexity of this process stems from the challenges in accurately forecasting future growth and the corresponding infrastructure needs. Forecasts are inherently uncertain and can result in either insufficient funding for necessary upgrades or excessive charges that might hinder development. Therefore, it would be critical for distributors and key stakeholders such as municipalities and developers to collaborate closely. By leveraging robust data analysis and forecasting techniques, they may be able to mitigate these risks and ensure a fair and efficient implementation of the FDC.

## 6.3 Standalone Rates

The third alternative that was identified for discussion was the concept of standalone rates derived from natural gas system expansions. It is also known as distribution expansion surcharges. In some areas, the cost of extending natural gas service is high due to the greater distances from existing pipelines and fewer customers. To address this, qualifying projects may use an expansion surcharge that removes any upfront costs for residents or businesses seeking gas service, spreading the expense over 40 years. When connecting to the existing pipelines is not economically viable at standard OEB rates, this surcharge is added to the regular rates for the applicable rate class. All new customers within the designated expansion area would be subject to the same expansion surcharge, and the charge is spread over a maximum period of 40 years.

**Stakeholder Comments on Standalone Rates**

Both ratepayer groups and developers agreed that this cost recovery approach has the potential to mitigate cross-subsidization between new and existing customers. However, they were concerned with risk allocation and emphasized that, without appropriate checks and balances in place, it should not be considered. On the other hand, distributors expressed concerns regarding the operational complexities associated with tracking individual expansions until they are paid off. This would require tracking mechanisms until each expansion is fully settled. They underscored the challenges in managing different rates for customers based on their expansion needs and time-of-use patterns, which could potentially complicate the billing process.

**OEB Analysis on Standalone Rates**

This approach eliminates the need for upfront payment from developers, spreading the expansion costs across all new customers on their monthly electricity bills. However, the OEB believes that implementing standalone rates for specific developments within a distributor’s service area would be very complex. While these standalone rates could potentially reduce developers’ capital contributions and uphold the beneficiary pays principle, they pose significant challenges. For each expansion project that is eligible for a standalone rate, the distributor will have to track the revenues collected from the standalone rate from customers who are connected to the expansion over a long period of time, until the costs of the expansion are fully recovered. In addition, managing multiple “standalone rate zones,” defining their boundaries within an interconnected electrical system, and integrating these rates into the existing billing systems are all complex tasks that could impose significant administrative burdens on distributors.

## 6.4 Upstream Charge

Some developers pointed to the past inclusion in the DSC of a provision for an “upstream charge,” to facilitate construction ongoing expansion of distribution facilities. This provision, known as the “enhancement cost” incorporated into the economic evaluation, was introduced in 2006 to improve transparency for customers in understanding how these costs are calculated. Distributors were required to annually estimate a per kilowatt enhancement cost based on a historical three to five year rolling average of actual enhancement costs from system expansions. The intent of this charge was to ensure that all new connecting customers were contributing to the costs of distribution facilities, and supporting the replacement of that system capacity, when they connected to the system. This concept is similar to an expansion rebate, where future customers who benefit from prior system expansions contribute to those costs.

Consequently, this enhancement charge became an additional cost for all new customer connections requiring expansion, including subdivisions. Since this charge was collected from all such connections, it resulted in substantial revenue generation, allowing distributors to allocate more funds toward capital investments through rates rather than categorizing these investments strictly as expansion costs.

In 2010, the enhancement cost was removed from the economic evaluation calculation. The OEB explained, at the time, that it was more appropriate for the distributor to bear the costs of all enhancements, given that they benefit all ratepayers. As a result, instead of collecting substantial enhancement costs from new customers, the costs of enhancements are now allocated across all ratepayers, spreading the financial responsibility more broadly and aligning the benefits that these investments provide across the customer base.

**Stakeholder Comments on Upstream Charges**

Some developers pointed out that the concept of the upstream charge should be reintroduced as a means of paying for system enhancements that support greenfield growth. Developers believed that the inclusion of this charge facilitated distributors in constructing expanded distribution facilities. In developers' opinion a reintroduced upstream or enhancements charge would encourage distributors to plan for and build out their systems to prepare for new growth.

**OEB Analysis on Upstream Charges**

The OEB is not convinced of the benefits of reintroducing the enhancement or upstream charge for subdivision developments in the near term, as it would require contributions from a significant number of new customers before distributors accumulate enough in the enhancement fund to undertake major infrastructure buildouts. This approach, even when first introduced in 2006, was not designed to replace the need for expansion charges. Instead, it meant that developers, in the short term, would face higher upfront contributions for the necessary expansion work to accommodate their developments. The reasons given by the OEB in 2006 for not charging an additional amount to new connections for enhancements are also still valid, in that enhancements are built for all customers, and thus are appropriately recovered as part of the distributor's rates.

## 6.5 Area-wide Growth Charges and Socialization of Costs

One ratepayer group suggested creating a new capital spending category that is driven by growth area and not attributable to a specific customer. This stakeholder also suggested a broader socialization of this growth capital to ensure that significant growth in a smaller territory does not unfairly burden the existing customers of that smaller distributor. Under this approach, the distributors would be allowed to recover the cost through a levy across a region rather than solely from their local customers. This new category of spending would be supported by a variation on fixed development charges that would allow a distributor to recover a fixed amount for growth areas from the connecting customers. The balance of any costs necessary to expand the system and connect to the growth area would be recoverable from a region of growth, rather than being borne by the ratepayers of the distributor building the expansion. This approach is intended to facilitate opening up growth areas that would be too costly to otherwise connect. At the same time, it recognizes the economic and social benefits of areas of significant growth in housing, which support broader communities with more residents seeking employment, conducting business and paying taxes, as well as the societal benefits from increased populations. The cost recovery model would socialize the cost of infrastructure expansions necessary to support new housing developments in those areas experiencing significant growth.

**OEB Analysis of Area-wide Growth Charges**
A significant barrier to this alternative is that the OEB has no mechanism to implement a proposal for a region wide recovery, as this would entail collecting distribution system costs from ratepayers of one distributor and redistributing these revenues between different distributors.

Beyond the implementation issue identified above, there are a number of challenges with the proposal that have been initially identified. The identification of growth regions would be challenging given the need to tie economic and social benefits to specific growth areas to justify collection of charges from other distributors' ratepayers. Customers in areas experiencing minimal or no growth in the coming years might end up subsidizing the infrastructure costs for new developments in more rapidly growing areas. It would be necessary to explore the question of identified benefits, both social and economic, as well as the impact on other communities in broader regions. A means for settling between distributors would also need to be identified.

## 6.6 OEB's Recommendation on Alternative Cost Allocation Approaches

The stakeholder views on all of these alternative approaches highlight the need for a thorough review and consultation before making any policy changes. It will be necessary to fully consider how any changes consider both development needs and the equitable allocation of costs among all stakeholders. In this consultation, only the highest-level of exploration of any of the alternatives was possible. Each alternative raises a number of questions regarding fairness to both existing and new customers, impacts on distributors' financing and planning, administrative burden and risk allocation. Further, as noted in stakeholder comments, any of these alternatives are likely to require extensive work to develop the level of detail to support their implementation, which could delay housing development as developers await the outcome.

Consequently, the OEB recommends that these alternative views only be pursued if the recommended changes to the connection and revenue horizons do not adequately address the financial burdens faced by “first movers.”

# 7 CONCLUSIONS

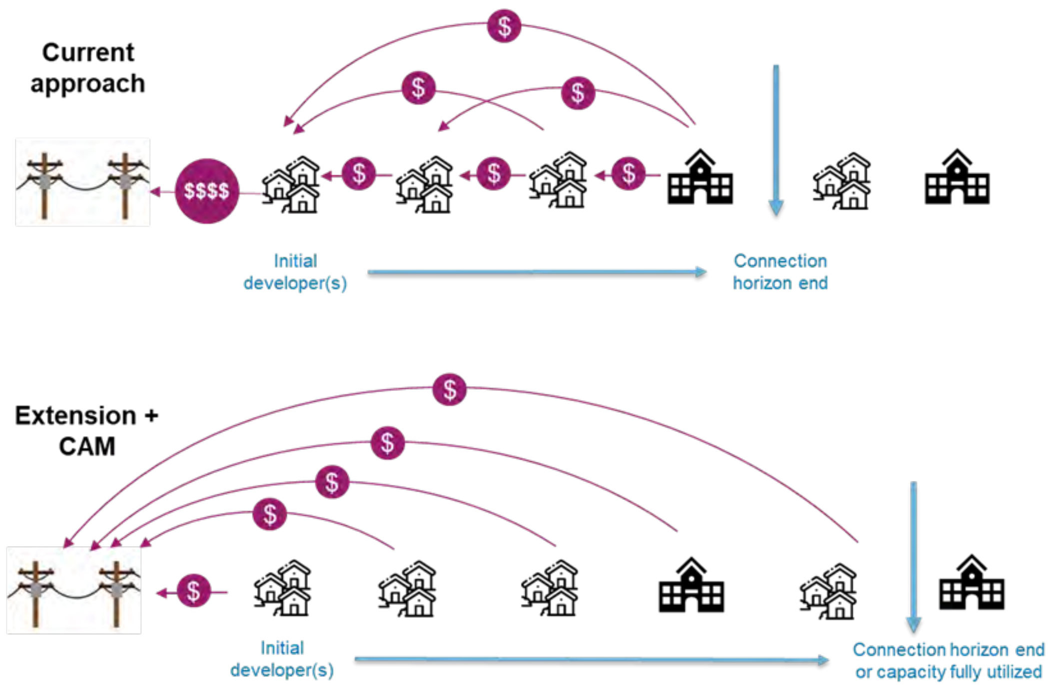
The OEB has reviewed its current cost recovery framework and assessed the feedback and insights gathered from stakeholders regarding the distribution system expansion for housing developments. This detailed consultation has illuminated specific challenges linked to large greenfield developments, notably the potential for considerable financial burdens to be shouldered by initial developers due to significant upfront infrastructure costs.

To address these issues, the OEB will propose targeted amendments to the DSC. These changes are intended to enhance clarity around the extension of the connection horizon and introduce a capacity allocation model designed to ensure equitable cost sharing among all customers. These amendments will facilitate appropriate planning and execution of necessary expansions, ensuring that they are both fair and cost-effective.

Specifically, the OEB recommends the following actions:

- Amending the DSC to provide clarity on distributors' discretion to extend connection horizon for specific circumstances.
- Amending the DSC to provide clarity regarding the process and requirements when the horizon is extended.
- Establishing a capacity allocation model that considers multi-customer, multi-year projects.
- Amending the DSC to extend the maximum revenue horizon for residential developments from 25 years to 40 years.

Further consultations, as part of the DSC amendment process, will be essential to refine the proposed changes. These consultations will focus on operationalizing the connection horizon extension, the capacity allocation model, and revenue horizon extension, with particular attention to maintaining fairness and minimizing administrative burdens. The diagram below provides a high level picture of the changes and their intended impact on developments.




Regarding the alternative cost allocation approaches discussed in this Report, the OEB will not proceed with further review unless the concerns of "first movers" persist following the implementation of changes to the connection and revenue horizons. These alternative methods present various challenges and risks, including the potential to shift costs from new to existing customers, and necessitating distributors to conduct detailed analyses and manage complex administrative processes. Therefore, the OEB will prioritize refining and observing the outcomes of the proposed changes before considering additional changes to the cost allocation framework.

During the consultation, developers highlighted additional concerns, which are detailed in the common feedback section of this Report and were also noted as feedback in the PwC report on development costs. The concerns identified by developers related to the connection process and insufficient communication by distributors regarding project design and progress that all affect the timely connection of developments. There was also a request for increased information about distribution system capacity to facilitate developers' planning processes. Developers suggested that these concerns are having both a direct and indirect impact on getting housing projects completed and the costs that developers are incurring. The OEB is of the view that these issues must be resolved. And the OEB will take action to address these concerns regarding the transparency, clarity and consistency of connection processes and requirements, including timelines and customer communication. This work is expected to result in the OEB providing guidance or direction to the sector and setting further performance expectations regarding customer connections. Distributors are expected, as part of providing good customer service, to provide ongoing communications to their customers to ensure that any delays are understood. Regarding concerns about information on system capacity, the OEB is already working to address this as part of its response to the Minister’s Letter of Direction and expects to issue direction on capacity mapping later this fiscal year.

As noted earlier, stakeholders called for improved planning to tackle infrastructure challenges in emerging communities, including calls from many developers for a provincial roundtable to discuss these issues. In 2022, the OEB’s Regional Planning Process Advisory Group provided guidance for distributors and municipalities that emphasized the need for collaboration and sharing information to increase planning process efficiency and consistency.

By making the proposed DSC changes, the OEB aims to facilitate more sustainable and equitable growth across the province. These changes are expected to provide the necessary flexibility and financial relief for developers, while safeguarding the interests of existing ratepayers, thereby supporting the province's broader economic and social objectives.

# Appendix I – Consultation Participants

| | |
|---|---|
| Alectra Utilities Corporation | Meeting & written comments |
| Association of Municipalities of Ontario | Stakeholder Meeting |
| Building Industry and Land Development (BILD) | Meeting & written comments |
| Bluewater Power Distribution Corporation | Stakeholder Meeting |
| Brookfield Property | Meeting & written comments |
| Brooklin North Landownders Group | Stakeholder Meeting |
| Building Owners and Managers Association | Stakeholder Meeting |
| Burlington Hydro Inc. | Stakeholder Meeting |
| Chestnut Hill Developments | Stakeholder Meeting |
| Coalition of Concerned Manufacturers and Businesses of Canada | Meeting & written comments |
| Consumer Council of Canada | Stakeholder Meeting |
| Cornerstone Hydro Electric Concepts | Stakeholder Meeting |
| Delta Urban Inc. (representing North East Pickering Landowners Group) | Meeting & written comments |
| DG Group | Stakeholder Meeting |
| Distributed Resource Coalition | Stakeholder Meeting |
| Eastern Ontario Wardens' Caucus | Meeting & written comments |
| Electricity Distributors Association | Meeting & written comments |
| Elexicon Energy Inc. | Meeting & written comments |
| Enbridge Gas Inc. | Stakeholder Meeting |
| Entegrus | Stakeholder Meeting |
| ENWIN Utilities Ltd. | Stakeholder Meeting |
| ERTH Power Corp | Stakeholder Meeting |
| Essex Powerlines Corporation | Stakeholder Meeting |
| Fieldgate Construction Management Limited | Meeting & written comments |
| GrandBridge Energy Inc. | Stakeholder Meeting |
| Great Gulf | Stakeholder Meeting |
| Halton Hills Hydro Inc. | Stakeholder Meeting |
| Hydro 2000 Inc. | Stakeholder Meeting |
| Hydro One Networks Inc. | Meeting & written comments |
| Hydro Ottawa Limited | Meeting & written comments |
| Independent Electricity System Operator | Stakeholder Meeting |
| Infrastructure Ontario | Stakeholder Meeting |
| InnPower Corporation | Stakeholder Meeting |
| Invest Windsor Essex | Stakeholder Meeting |
| Lakeland Holding Ltd. | Stakeholder Meeting |
| Lakeview Homes | Stakeholder Meeting |

| | |
|---|---|
| London Hydro Inc. | Stakeholder Meeting |
| Lormel Homes | Stakeholder Meeting |
| Low-Income Energy Network | Meeting & written comments |
| Mattamy Homes Canada | Meeting & written comments |
| MQ Energy Inc. | Stakeholder Meeting |
| Newmarket-Tay Power Distribution Ltd. | Stakeholder Meeting |
| Niagara-on-the-Lake Hydro Inc. | Stakeholder Meeting |
| Niagara Peninsula Energy Inc. | Stakeholder Meeting |
| Oakville Hydro Electricity Distribution Inc. | Stakeholder Meeting |
| Ontario Energy Association | Meeting & written comments |
| Ontario Home Builders' Association | Stakeholder Meeting |
| Orangeville Hydro Limited | Stakeholder Meeting |
| Orlando Corporation | Meeting & written comments |
| Over Under Engineering Services Ltd. | Stakeholder Meeting |
| Pollution Probe | Meeting & written comments |
| Power Advisory LLC | Stakeholder Meeting |
| Provident Energy Management Inc. | Stakeholder Meeting |
| RTG Systems Inc. | Stakeholder Meeting |
| SAH Workshop Organizing Committee | Written comments |
| School Energy Coalition | Meeting & written comments |
| Strategy Corp Inc. | Stakeholder Meeting |
| Sundial Homes | Stakeholder Meeting |
| The Atmospheric Fund | Stakeholder Meeting |
| Tillsonburg Hydro Inc. | Stakeholder Meeting |
| Toronto Hydro-Electric System Limited | Meeting & written comments |
| Utilis Consulting Inc. | Stakeholder Meeting |
| Utilities Kingston | Stakeholder Meeting |
| Vulnerable Energy Consumers Coalition | Stakeholder Meeting |
| Welland Hydro-Electric System Corp. | Stakeholder Meeting |
| Wellington Northpower Inc. | Stakeholder Meeting |
| Western Ontario Wardens' Caucus Inc. | Stakeholder Meeting |

ONTARIO ENERGY BOARD

# Part II

# Unit Cost Benchmarking – Communities, Subdivisions and Electrification

# Contents

# Disclaimers

Our Services were performed, and this Report was developed, in accordance with our Statement of Work dated February 14, 2024, and are subject to the terms and conditions included therein.

Our role is advisory only. The Ontario Energy Board [OEB] is responsible for all management functions and decisions relating to this engagement, including establishing and maintaining internal controls, evaluating, and accepting the adequacy of the scope of the Services in addressing the OEB's needs and making decisions regarding whether to proceed with recommendations. The OEB is also responsible for the results achieved from using the Services or deliverables.

Our work was limited to the specific procedures and analysis described herein and was based only on the information made available from February 14, 2024, to June 12, 2024. Accordingly, changes in circumstances after this date could affect the findings outlined in this Report.

We are providing no opinion, attestation or other form of assurance with respect to the information upon which our work is based, and we did not verify or audit any information provided to us. This Report has been prepared for the use and benefit of, and pursuant to a client relationship exclusively with, the OEB ("Client"). Any third party relying on the Report does so entirely at their own risk and shall have no right of recourse against PwC, and its partners, directors, employees, professional advisors, or agents. PwC disclaims any contractual or other responsibility to third parties based on its use. None of PwC, its partners, directors, employees, professional advisors, or agents accept any liability or assume any duty of care to any third party (whether it is an assignee or successor of another third party or otherwise) in respect of this Report.

# 1. Executive Summary

## 1.1 Purpose of this Study

The Minister of Energy provided a Letter of Direction to the Ontario Energy Board (OEB) in November 2023 which outlined the government's priorities and information that was needed from the OEB. One priority is to construct 1.5 million new homes in Ontario by 2031, while managing reliability, affordability and resiliency within Ontario's energy system. As a result, the Minister encouraged the OEB to "review electricity infrastructure unit costs in the electricity sector" and share a report back.[1] Observations from this study will provide insights on cost variances and other areas of opportunity for Ontario electricity distributors.

## 1.2 Scope of this Report

PricewaterhouseCoopers (PwC) Canada was engaged by the OEB to assist with the study. The scope of our evaluation is examining the electricity new connection costs and process – referring to the process of linking a newly constructed development to existing electricity infrastructure - focusing specifically on residential subdivisions. This study has the following objectives:

1. Leverage a consistent cost benchmarking framework to calculate and compare electricity distributors' design and construction costs across Ontario, using typical new electrical connection scenarios
2. Highlight sensitivity factors and provide perspective on the key drivers of cost variances
3. Conduct a jurisdictional review of practices being used in other provinces and understand potential challenges for new connections in Ontario.

This report highlights key observations on the connection costs of new subdivisions and contextual findings on processes and timelines that may impact the cost of new connections and the construction of new homes.

## 1.3 Key Observations and Implications

The surveyed data of unit costs determined the average estimated unit cost for subdivision electrical infrastructure for a gas heated community was $7.5K per lot and for an all-electric community was $12.2K per lot. Upstream of the subdivision costs, the study identified that the average estimated unit cost for overhead primary line to be $551k per kilometer and the average estimated unit cost for underground primary line to be $1,581k per kilometer.

Several observations were identified when looking at cost variance, timelines and processes. These observations were extracted from: surveys and in-depth interviews conducted with electricity distributors and builders/developers who are active in the Ontario market; and examination of industry trends and practices across Canada.

1. There are large variances in the new connection processes between electricity distributors due to varying construction methods, assumptions, and design and estimation standards, which can have an impact both on connection costs and timelines.
2. The rising material costs and labor supply shortages are of concern for Ontario electricity distributors as development accelerates.
3. Timelines and rework are of concern to developers and Ontario electricity distributors.
4. Distribution system capacity constraints represent a significant concern for new subdivision construction.
5. Utilities comprise a small portion of development cost/timelines; however, they can still impact costs, timelines, and the overall goal of accelerating the development of 1.5 million new homes in Ontario. Other factors, such as land permits, inflation, and market trends, also impact development costs and timelines.

It is important to note that some limitations existed in the gathering and interpretation of information, such as sample size, data availability, and the time horizon of the data, among others. These observations and limitations are explored in more depth in the following sections of this report. These observations have highlighted key areas

[1] OEB. *Letter of Direction from the Minister of Energy (2023)*.

where costs are rising and timelines are being impacted, which are being exacerbated by macroeconomic and industry trends. Ultimately, these factors can impact the goal of accelerating the development of 1.5 million new homes while maintaining cost efficiency.

# 2. Introduction and Approach

## 2.1 Background

As Ontario strives to construct 1.5 million new homes by 2031, the OEB, in response to a Letter of Direction from the Minister of Energy, has embarked on a study to understand Ontario electricity distributor costs, processes and timelines; learn about policies and procedures across Canada; and identify next steps, to support efficient and cost-effective new connections and, ultimately, support accelerated, affordable home development.

As housing needs increase across Canada, demand on electricity distributors to provide new connections and expansions efficiently and effectively also increases. This study examines Ontario electricity distributors' new connection costs, variances, and drivers of those variances. While the focus of the study is electricity distributors' costs, processes and timelines were also examined as these can affect new connection costs and the province's overarching development goals. It is important to note that there are a variety of factors that go into building a new home, such as land procurement and permits, connecting various utilities, and infrastructure construction, among others. There are also many factors, including labor and material shortages, fluctuating interest rates, and inflation, among others, that impact the demand, timelines and cost of new home development. Electrical connection costs and timelines tend to represent a small fraction of the total cost and time of development, and these other factors have an impact on costs and timelines as well.

### *2.1.1 New Connections Background Information*

As new residential subdivision developments are created – whereby land is divided into smaller lots where properties are built - essential services, such as electricity, water, gas, and telecommunication lines, must be designed and constructed. To move forward with construction, developers need confirmation that the new development can be swiftly, and cost efficiently, integrated into the pre-existing infrastructure, providing safe, reliable and affordable access to these vital utilities.

To connect electricity to a new home, developers must work with electricity distributors to bring electrical service to the new subdivision, referred to in the industry as developing a new connection. A new connection refers to the process of establishing the physical links between a newly constructed residential area to an existing electrical utility grid. The new connection process begins with a developer or customer initiating a request, followed by the completion of a design and cost/timeline estimate. Once the estimate is approved by the developer, material is procured, planning for installation is completed, and the developer works with contractors or electricity distributors to execute the build and construction of the new connection. The timelines for this process in addition to executing the subdivision new connections vary depending on the size and scope of the proposed project. Additionally, the process of a new connection varies depending on a variety of factors, such as project scope and whether the developer selects the Alternative Bid approach, where a developer selects a contractor to complete the work, instead of an electricity distributor. This can create variations in cost, timelines, and stakeholders involved in the process. These variances will be examined in more detail in the following sections.

There are three main components of construction, as demonstrated in Figure 1 – system expansion, the primary line expansion and the subdivision electrification. System expansion is defined as a "modification or addition to the main distribution system in response to one or more requests for one or more additional customer connections that otherwise could not be made."[2] In the Distribution System Code (DSC), this includes capacity increases, and extensions for the primary line and subdivision electrification. For the purpose of the analysis in this report, we have separated primary line and subdivision electrification components from the system expansion definition. The primary line expansion involves bringing electricity to the subdivision from the distribution substation, while the subdivision electrification includes the build of the electrical infrastructure within a subdivision to service each lot and home. This study focuses on the primary line expansion and subdivision electrification, and all data gathered in subsequent sections assumes that capacity is available.

[2] Ontario Energy Board. *Distribution System Code*.

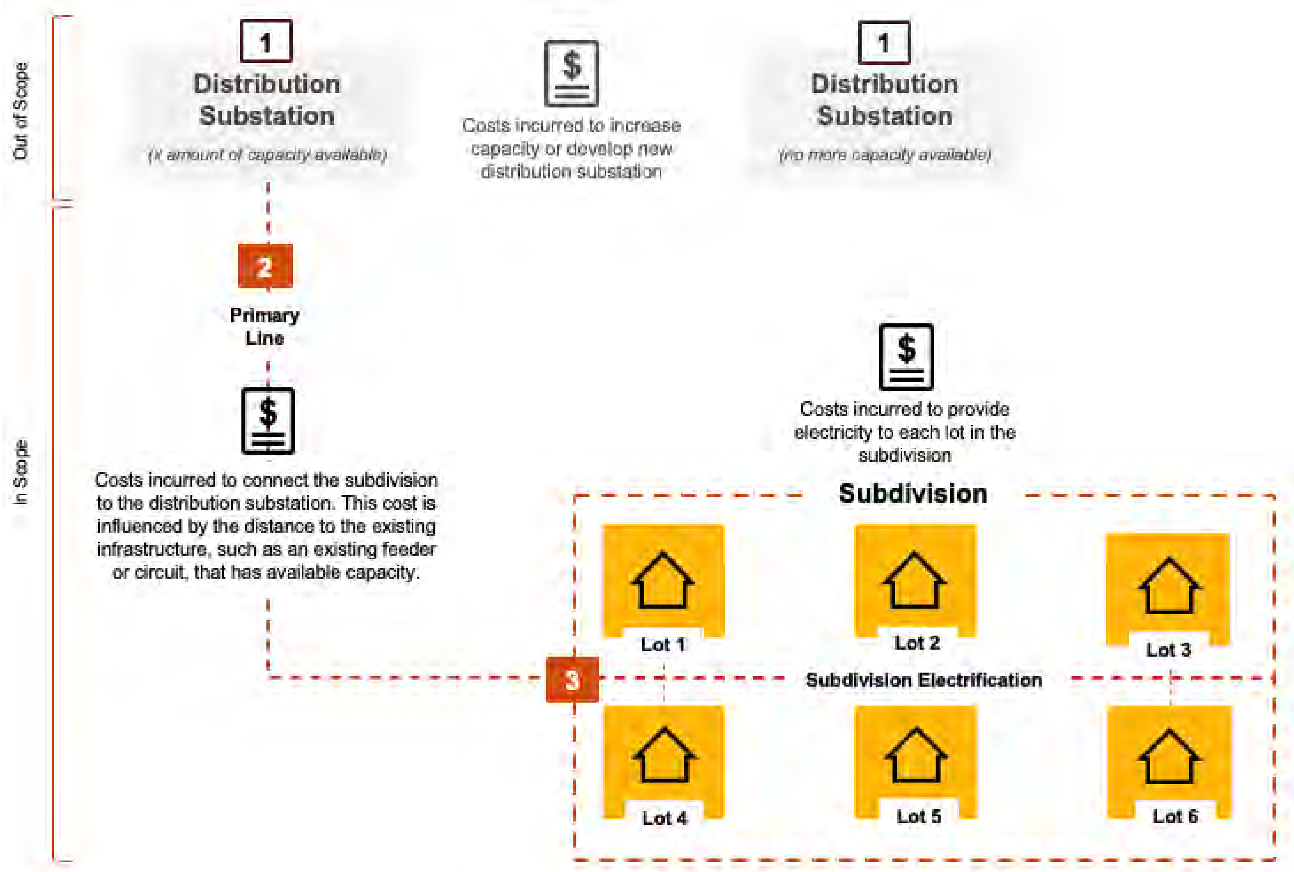



**Figure 1 - Distribution System Overview**

It is important to note that a variety of factors can impact the cost of new electrical connections. Availability of capacity at distribution substations in the area, the distance between a subdivision and existing electrical distribution infrastructure, and the electrical needs of the subdivision can all impact cost and timelines of development. While electrical connection costs represent a small fraction of the total cost of new home construction, capacity availability in the distribution system can substantially impact cost and timelines as capacity may need to be increased.

## 2.2 Approach

To better understand how new connections and cost estimations are established, the variances that exist and areas of opportunity, three main activities were conducted over the period of February 2024 to June 2024:

1. *Cost Data Review and Stakeholder Interviews:* Engage with Ontario electricity distributors to estimate unitized costs across a variety of scenarios for new subdivision connections, identifying variances and their underlying drivers. Engage with Ontario builders/developers and electricity distributors to gather additional context on cost estimation process, timelines, and areas of opportunity for the province.
2. *Industry Analysis:* Understand the broader economic and industry trends that are impacting utilities' distribution capacity, labor, material, and new connection costs across Canada. Identify how these trends may impact Ontario electricity distributors' costs and timelines.
3. *Jurisdictional Review:* Examine approaches and policies across Canada that promote cost efficiency and streamline new connection processes.

The specific methodology used for each activity and the observations that were identified are highlighted in the following sections.

# 3. Cost Data Analysis

Eleven electricity distributors in Ontario were contacted for this study, located in areas projected to experience medium to high housing growth over the next decade. Out of these electricity distributors, seven agreed to participate, and six were able to provide usable cost estimates, collectively serving approximately 2.8 million residential customers as of 2022.[3] Altogether, nearly half (48.6%) of Ontario's goal of 1.5 million new homes by 2031 are attributed to these electricity distributors.[4]

A representative sample of housing subdivision scenarios were designed, covering the bulk of new subdivision builds in areas served by participating electricity distributors. This approach facilitated the collection of standardized cost estimate data for common subdivision construction scenarios, enabling a comparative analysis of cost variances and subsequent discussions with the electricity distributors to explore the root causes of these differences.

Beyond collecting cost data, surveys were shared with all seven participating electricity distributors. Survey data was gathered, and, in some instances, interviews were also conducted with six electricity distributors and three select developers who are active in Ontario. The goal was to understand relative variances in current design and estimation processes, and to gather feedback on areas of concern and opportunity relating to new connections in subdivision developments.

## 3.1 Reference Case Scenarios and Input Parameters

A framework of reference scenarios for residential subdivisions was established to collect cost benchmarking data from the electricity distributors, as depicted in Figure 2. At a high level, the scenarios differentiate between greenfield and brownfield developments. Greenfield developments were assumed to be on land that was not previously developed, requiring the extension of a primary line from the existing distribution network to the subdivision. In contrast, brownfield scenarios typically involve infill development on vacant or underutilized land within already developed urban areas, negating the need for new primary line expansions.

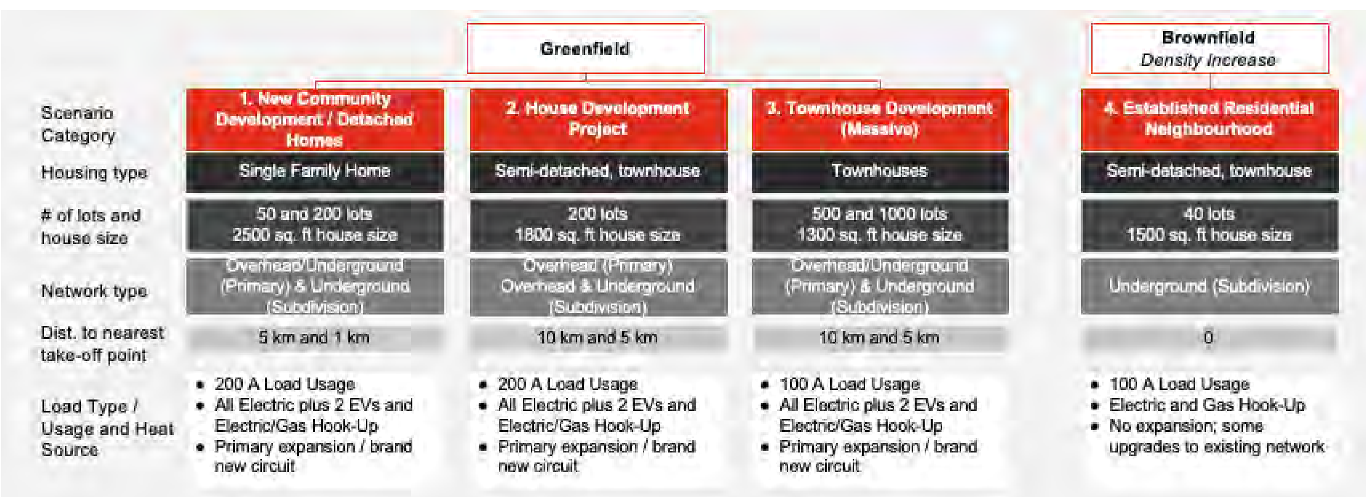



**Figure 2 - Residential Reference Scenarios**

The framework in Figure 2 was to develop the ten reference case scenarios showcased in Figure 3 below. Data was gathered from the participating electricity distributors for each of the ten scenarios. More information on the data request template has been attached in Appendix 2.

[3] OEB. *2.1.2 Customers & Connections (SSS + Retailer) - Table 2 Total SSS Customers & Connections Excel*
[4] Ontario Government. *Tracking housing supply progress.*

| Scenario Inputs | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| # | Scenario | Build type | Lot type | Number of lots | House Size (sq ft) | Lot Size (sq ft) | Load Type / Usage | Distance to nearest takeoff point (km) | Primary Construction | Subdivision Construction | Energy Availability | Projected In-Service Date | Additional Context |
| 1 | New Upscale Community | Greenfield | Single Family Home | 50 | 2500 | 3600 | 200 A | 5 | Underground | Underground | All Electric (Water and Heating), Plus 2 EVs | 2024 | Primary expansion of brand new circuits |
| 2 | New Upscale Community | Greenfield | Single Family Home | 50 | 2500 | 3600 | 200 A | 5 | Overhead | Underground | Electric and Gas Hook-up | 2024 | Primary expansion of brand new circuits |
| 3 | New Upscale Community | Greenfield | Single Family Home | 200 | 2500 | 3600 | 200 A | 1 | Underground | Underground | All Electric (Water and Heating), Plus 2 EVs | 2024 | Primary expansion of brand new circuits |
| 4 | Houses Development Project | Greenfield | Semi-Detached Townhouses | 200 | 1800 | 3000 | 200 A | 10 | Overhead | Overhead | Electric and Gas Hook-up | 2024 | Primary expansion of brand new circuits |
| 5 | Houses Development Project | Greenfield | Semi-Detached Townhouses | 200 | 1800 | 3000 | 200 A | 5 | Overhead (Major road crossing 12 lane hwy) | Underground | All Electric (Water and Heating), Plus 2 EVs | 2024 | Primary expansion of brand new circuits |
| 6 | Townhouses Development Project (massive) | Greenfield | Townhouses | 500 | 1300 | 1500 | 100 A | 5 | Overhead | Underground | Electric and Gas Hook-up | 2024 | Primary expansion of brand new circuits |
| 7 | Townhouses Development Project (massive) | Greenfield | Townhouses | 300 | 1300 | 1500 | 100 A | 10 | Underground | Underground | All Electric (Water and Heating), Plus 2 EVs | 2024 | Primary expansion of brand new circuits |
| 8 | Townhouses Development Project (massive) | Greenfield | Townhouses | 1000 | 1300 | 1500 | 100 A | 5 | Overhead | Underground | Electric and Gas Hook-up | 2024 | Primary expansion of brand new circuits |
| 9 | Townhouses Development Project (massive) | Greenfield | Townhouses | 1000 | 1300 | 1500 | 100 A | 5 | Underground | Underground | All Electric (Water and Heating), Plus 2 EVs | 2024 | Primary expansion of brand new circuits |
| 10 | Established Residential Houses Neighborhood (Including Infill Scenarios) | Brownfield (density increase) | Semi-Detached Townhouses | 46 | 1500 | 1500 | 100 A | 0 | | Underground | Electric and Gas Hook-up | 2024 | No expansion (Replace 5 existing 2100sqft homes with 100A connections on 60x120 lots with 40 new townhomes) Some upgrades to existing network |

**Figure 3 - The Ten Reference Case Scenarios for Data Gathering**

Several characteristics were considered in shaping up the reference model scenarios for cost estimation. The following input factors were varied across each scenario to understand the different drivers of the subdivision connection costs:

1. **Build and lot type -** Covers build type across four major types of new housing residential projects, which can be greenfield or brownfield:

| | | |
|---|---|---|
| Greenfield | New Community Development / Detached Homes | These projects are centered on the creation of single-family homes in newly developed areas, typically serving large loads (200 A). |
| | House Development Project | Focused on constructing semi-detached homes and townhouses. |
| | Townhouse Development (Massive) | This large-scale project is committed to the development of townhouses, providing a compact, community-focused living space optimizing land utilization. |
| Brownfield | Established Residential Neighbourhood | Focused on revitalizing an existing neighborhood, this project upgrades semi-detached homes and townhouses. |

2. **Number of lots -** refers to the division of a larger parcel of land into smaller segments or lots, upon which properties are constructed and subsequently sold to investors or customers. The number of lots varies across each scenario, with an increase in lots indicating a greater number of homes that require services. Consequently, this would lead to an increased demand for electricity (both distribution system capacity and peak load), which may affect the necessary distribution infrastructure development and the labor hours required.

3. **House Size and Lot Size -** represents the square footage occupied by the house or lot within the subdivision, with variations across different sub-categories of scenarios. Generally, larger homes and lots are expected to require more electricity due to additional energy needs of a larger space and/or a higher number of appliances. This increased demand can influence the type of materials and infrastructure required. However, based on the scenarios selected for this study, house and lot sizes were not anticipated to be significant cost drivers.

4. **Primary and Secondary Construction -** differentiates between the primary network, which connects the subdivision to the larger distribution grid, and the secondary network, which is the internal network within the subdivision itself. Both networks may be built either using overhead / above-ground infrastructure, such as poles and wires, or with the cables undergrounded, even though overhead is not very common for subdivision electrification in the service territories being considered in this study.

   Both the primary and secondary networks necessitate labor and design work, which electricity distributors may choose to outsource or manage internally, a decision that can affect the connection costs. While overhead construction tends to be relatively easier, underground construction requires more extensive planning and execution, including drilling or digging through various terrains like soil, concrete (typically in urban areas with existing road, sidewalks, or other concrete structures), or rocks, to lay cables beneath the ground surface. The connection methodology to build the primary network infrastructure are expected to have significant impacts on overall connection costs.

5. **Distance to Nearest Take-off Point** - refers to the proximity of the service lines branching off from the main distribution network to the properties they serve. Greater distances to the point of supply can increase the infrastructure, materials, labor hours, and effort required for energization, thereby affecting the overall cost of a new residential subdivision.

6. **Load Usage** - measures the demand for energy consumption by various load types over a specified period, typically in kilowatts (kW). The study examines scenarios with 100-amp and 200-amp service capacities. These are determined by the type of applications and load requirements of different housing scenarios, with higher loads requiring a more robust distribution system to reliably handle the increased demand, leading to the need for additional infrastructure. For the purpose of this study, an assumption was set that there are two EVs for the all-electric scenarios.

7. **Energy Usage** - the study contrasts two types of energy availability scenarios, with homes that are conventionally heated by natural gas and those that are heated entirely by electricity. This distinction is crucial in the context of the ongoing shift towards electrification. In scenarios where only electricity is used, especially for major appliances, there is a greater demand on electricity distributors. This increased load can require more substantial infrastructure to ensure reliable service, influencing overall cost.

Certain assumptions were made to enhance the focus of this study and identify factors with the largest impact to cost variances across electricity distributors and scenarios:

1. Upstream network upgrades are not needed, and the system is assumed to have adequate distribution capacity (under the DSC subdivision developments are not responsible for transmission level upgrade costs; this assumption only focuses on distribution capacity). Instead, this study will focus on two cost categories (Figure 4):
   - Primary line expansion
   - Subdivision electrification
2. Photovoltaic (PV) panels and home battery packs are not considered.
3. Estimates will include contestable and non-contestable work.
4. Estimates will exclude easements, permitting and licensing costs.
5. Primary ownership of poles in the area is with the utility (not owned by joint partners).
6. All premises will come online within 1-2 months of construction completion.

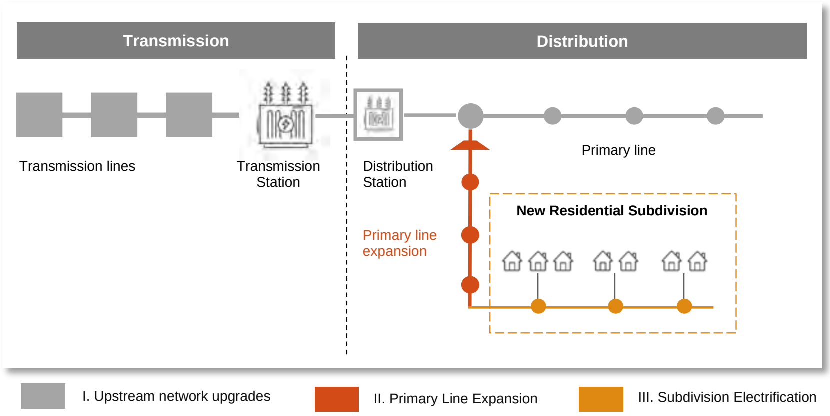



**Figure 4 - Key electricity costs categories for new subdivision build**

## 3.2 Cost Data and Qualitative Insights

### *3.2.1 Summary of Findings and Key Drivers of Cost Variances*

In order to conduct the cost variance analysis, average cost per kilometer and cost per lot were calculated across all scenarios and electricity distributors. The two sensitivity factors observed to have the biggest impact on cost were the construction method for the primary line expansion (overhead or undergrounded) and whether the subdivision was fully electrified or heated primarily by natural gas. Below is a summary of cost averages across all scenarios broken down by these sensitivity factors and the primary drivers of cost variance, uncovered through discussions with the participating electricity distributors and developers.

| Overhead Average Cost | Underground Average Cost | Gas Heated Average Cost | All Electric Average Cost |
|---|---|---|---|
| $551K / km | $1,518K / km | $7.5K / lot | $12.2K / lot |
| Min: $319 / km<br>Max: $1,060 / km | Min: $767 / km<br>Max: $2,695 / km | Min: $3.3 / lot<br>Max: $11.3 / lot | Min: $11.9 / lot<br>Max: $12.4 / lot |

**Drivers of Variance**

- **Excavation methods:** Different methodologies, such as directional drilling and trenching, were used for underground construction estimation costs. These methods vary in terms of restoration required and equipment required, creating variance in cost.
- **Electrical and construction standards:** Different standards, such as the choice of concrete encasement, the number of electric circuit phases to construct for, and variations in material standards contributed to cost differences.
- **Design and Estimation Assumptions:** Electricity distributors estimated costs based on their standards and made various assumptions to develop the cost estimates. These differences in assumptions also contributed to cost variances.
- **Overhead variance:** Overhead construction cost variance can be explained through varying assumptions that electricity distributors made, as well as the introduction of restoration costs in certain overhead construction situations, depending on the setting in which overhead work was assumed to take place.

**Drivers of Variance**

- **Economies of scale:** Varying levels of experience for electrification scenarios and the size of the electricity distributor, which contributes to operational efficiency, created variance as those with more expertise and efficiencies could unlock cost effectiveness.
- **Design Standards:** Current standards for materials and design, such as the typical size of cables, impacted the variances for all electric scenarios. For example, those who require more changes in their design standards to accommodate all electric scenarios may incur more costs for different materials than they would use for gas heated scenarios.

These variances and the drivers of the variances are explored in more depth in the following sections.

### *3.2.2 Electrical Infrastructure Cost Unitization*

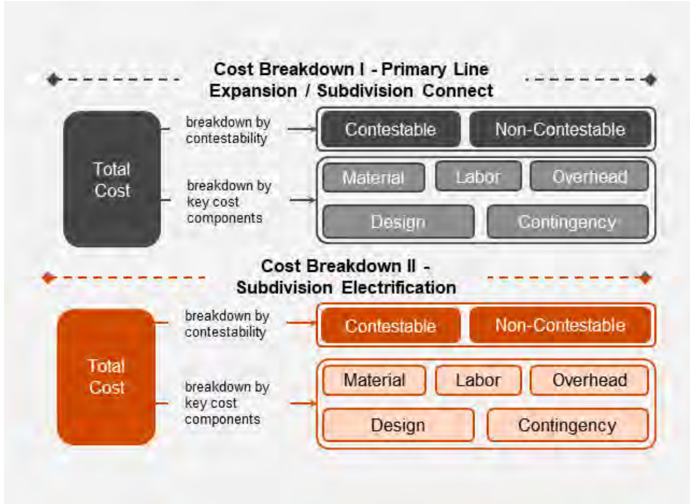



**Figure 5 - Total Cost Analysis Framework**

To facilitate comparison and cost unitization, electricity distributors' cost data was standardized based on two primary breakdowns (Figure 5)

I. **Cost per kilometer** for primary line expansion, and
II. **Cost per lot** for subdivision electrification

Each of these cost roll-ups are further disaggregated based on:

- **Contestability**: Contestable work is work in the new connection process that can either be completed by the electricity distributor or a contractor hired by the developer, whereas non-contestable work must be completed by the electricity distributor.
- **Cost Components**: explain what portion of the overall build cost can be attributed to materials, labor, design, contingency and overhead, such as administration.

The average overall costs across electricity distributors and the ten reference scenarios were calculated to be $973K per kilometre for primary line expansion plus $9K per lot for subdivision electrification, with most of the costs attributed to material and labor. As well, while a larger portion of the primary line expansion work was treated as non-contestable due to the specialized engineering expertise of the LDCs, there was greater flexibility in what portion of the work may be treated as contestable with regard to subdivision electrification (Figure 6).

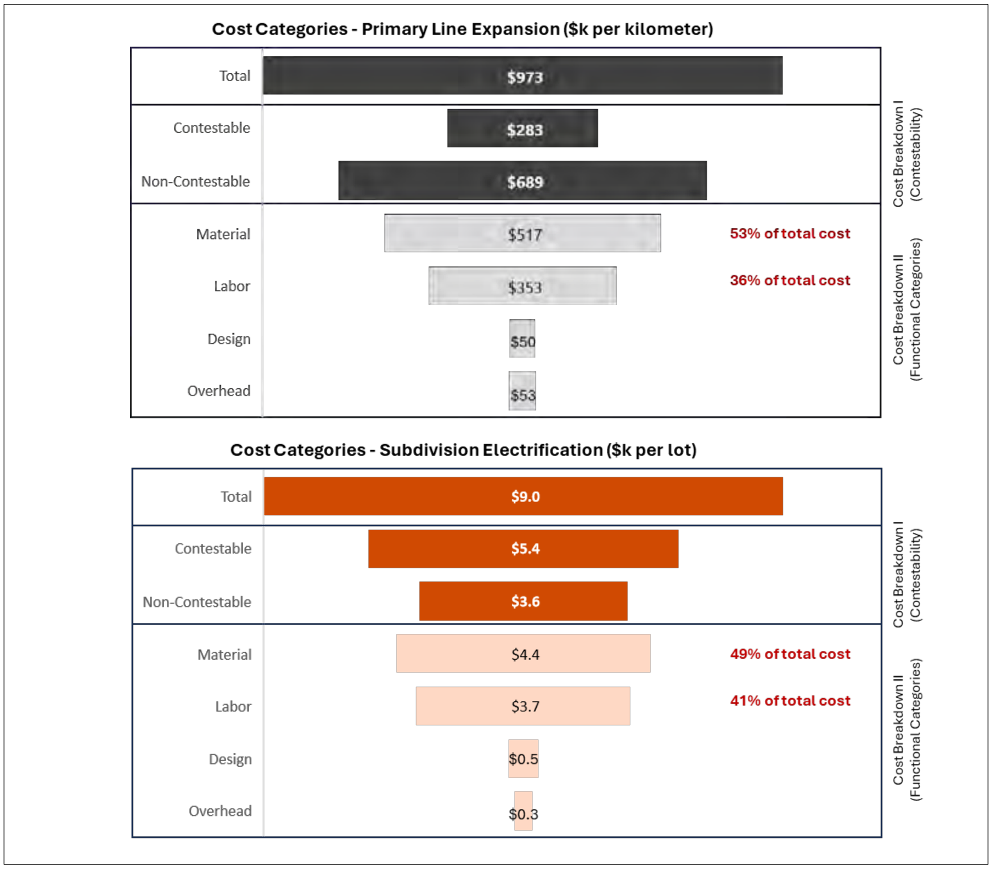



**Figure 6 - Cost breakdown for primary line expansion ($k per kilometre) and subdivision electrification ($k per lot)**

### *3.2.3 Sensitivity Analysis*

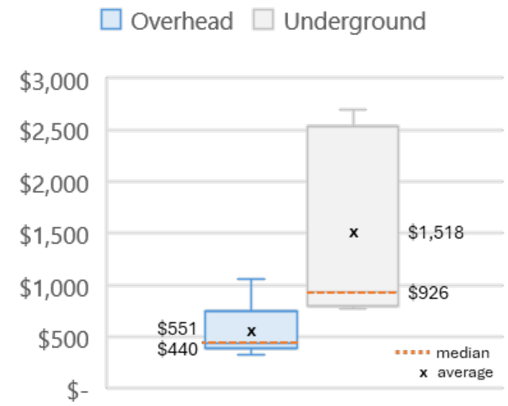
A review of the cost data highlighted two overarching design decisions in the construction of the primary line expansion and the subsequent electrification of the subdivision, which had the largest impact on overall cost variance (due to material selection, labor availability, and construction methodologies):

1. **Primary line construction** - if the lines were being run overhead, or if they were undergrounded, and
2. **Degree of subdivision electrification** - if the development relied on natural gas or exclusively electricity as its primary source of heating

Please refer to Appendix 2: Cost Estimation Template for electricity distributors if you would like to review specific scenarios associated with each observation.

**Observation # 1: Scenarios involving underground infrastructure for the primary line expansion consistently showed higher costs per kilometer and greater variance compared to overhead scenarios.**

On average, underground primary networks cost $1,518K per kilometer, which is nearly three times the cost of overhead alternatives at $551K per kilometer.




| | | |
|---|---|---|
| **Min** | $ 319 | $ 767 |
| **Max** | $ 1,060 | $ 2,695 |
| **Median** | $ 440 | $ 926 |
| **Mean** | $ 551 | $ 1,518 |

**Figure 7 - Primary Line Expansion Cost Variance ($k per km)**

As well, a greater range was observed between the two scenarios for the primary line, with $1,928K per kilometer for underground compared to $741K per kilometer for overhead lines (Figure 7). This significant cost difference is attributed to the complex and labor-intensive processes required for underground construction, such as drilling or trenching, and the subsequent restoration of the landscape and varying terrain. These activities require additional equipment, materials, and labor, driving up costs. In contrast, overhead construction of the primary line, involving the installation of poles and wires, is generally less complex and less costly. The large range for the overhead construction was due to varying assumptions by electricity distributors and restoration costs that may be needed for certain types of overhead primary line construction.

Looking at the primary line costs breakdown across the major functional categories highlighted that most of the costs are distributed across material and labor (87-91%).

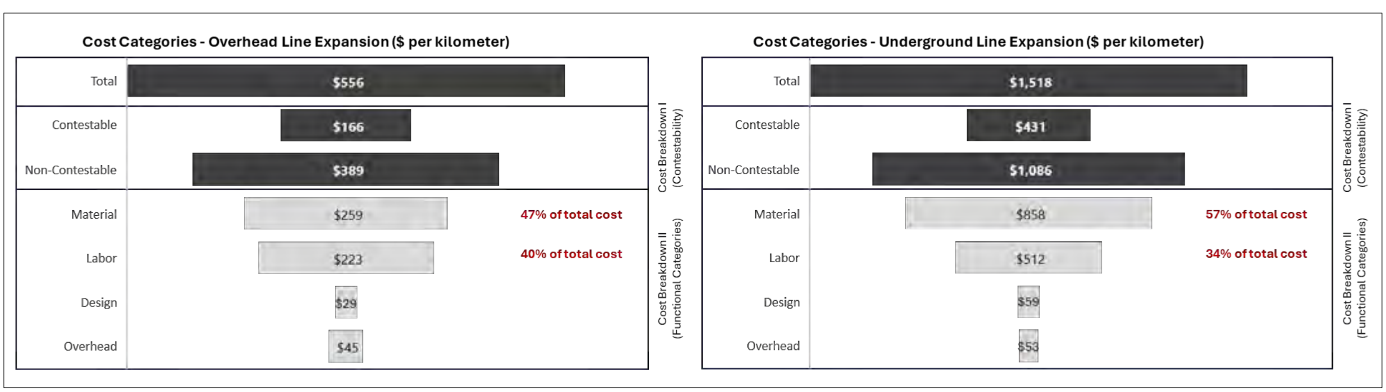



**Figure 8 - Breakdown of overhead vs. underground primary line expansion costs ($k per kilometre)**

**Factors driving cost variances:**

- **Excavation methods:** Two primary methods for undergrounding were examined for the primary lines - directional drilling and trenching. Directional drilling involves drilling a hole and threading cables through, which, despite the high cost of equipment like vacuum excavators, can reduce land disturbances and, consequently, overall costs. Trenching, while initially less expensive, often leads to higher costs due to extensive digging and the need for land restoration, impacting a larger area.

- **Electrical and construction standards:**
  - Some electricity distributors employ concrete encasement or ducted lines for future maintenance ease, while others use duct banks without concrete encasement to lower costs.
  - The choice of electric circuit phases also affects costs. Some electricity distributors standardize on three-phase circuits instead of a single-phase circuit, while others adjust phases based on material availability and projected load.
  - Variations in material standards contribute to cost differences.

- **Design and Estimation Assumptions:** Electricity distributors estimated costs based on their standards, leading to variances, especially in less common or newer scenarios in their service territory. For instance, one electricity distributor's assumption of no bends in directional drilling simplified the primary line underground connection process, which may reduce the estimated new connection costs. Another electricity distributor assumed concrete encasements for all underground scenarios in this estimation exercise, which may result in higher estimated new connection costs.

We observed that primary line expansion electricity distributor cost averages remain consistent across scenarios, with overhead costs showing minimal variance (up to 3%) compared to the overall cost per kilometer. In contrast, primary line underground costs exhibit a more significant variance (up to 10%) when compared to the overall underground cost per kilometer (Figure 9).

The scenario that includes the overhead primary line crossing of a major roadway is associated with a higher cost due to the need for additional specialized infrastructure required for such projects.

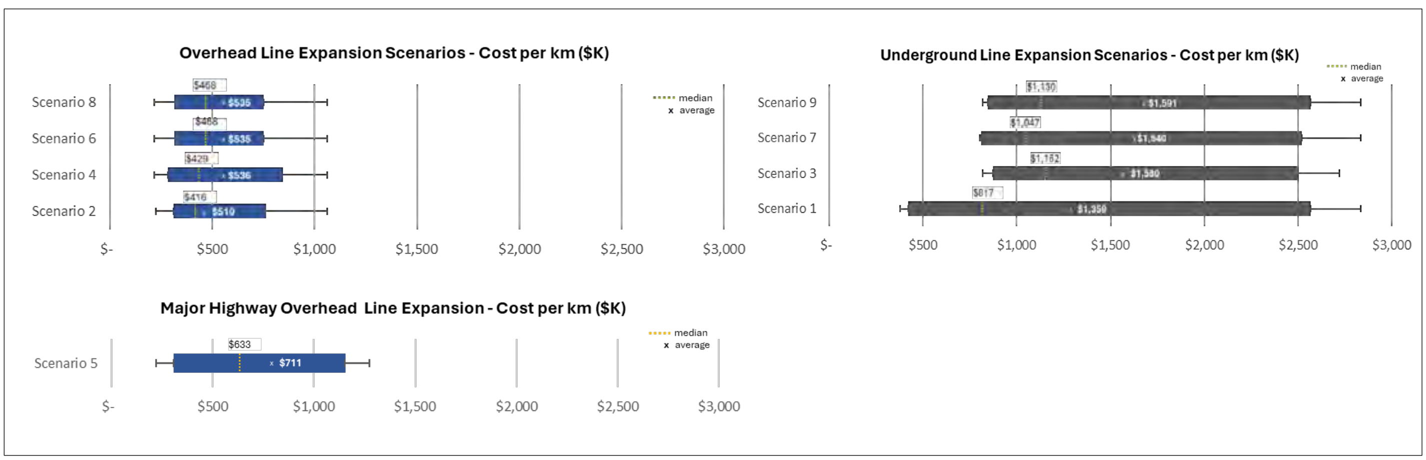
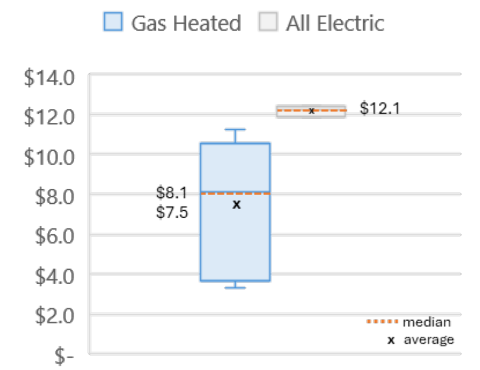



**Figure 9 - Cost averages for participating LDCs broken down by Underground and Overhead Line Expansion Scenarios (costs in $k per kilometer)**

**Observation #2: Fully electrified subdivisions, including those that use electricity for heating, tend to incur an additional average cost of $4.5K compared to those heated with natural gas.**

The cost per lot for electrification within subdivisions varies, averaging between $7.5K and $12K. This cost differential is influenced by the subdivision's reliance on electricity versus natural gas for heating, as illustrated in Figure 10. For both scenarios, around 90% of costs were attributed to material and labor (Figure 11).




| | | | | |
|---|---|---|---|---|
| **Median** | $ | 8.1 | $ | 12.2 |
| **Mean** | $ | 7.5 | $ | 12.2 |
| **Min** | $ | 3.3 | $ | 11.9 |
| **Max** | $ | 11.3 | $ | 12.4 |

**Figure 10 - Subdivision Electrification Cost Variance ($K per lot)**

It is important to note that nearly two thirds of the LDCs consulted as part of this study cited a lack of extensive experience with fully electrified subdivisions, leading to a scarcity of estimates for these scenarios. This gap necessitates a cautious approach when interpreting the data. To gain a clearer understanding of the cost drivers and current practices, interviews were conducted with LDCs and developers.

The discussions with LDCs highlighted that the higher costs associated with fully electrified subdivisions are due to the increased load demands, necessitating higher material costs. For example, LDCs may need to upgrade from standard cable sizes to larger ones for electric scenarios, resulting in higher costs. Additionally, the need for more transformers is driven by the fact that each transformer serves fewer homes, meeting the higher capacity needs of each household. These changes in materials for connections significantly affect the overall project costs.

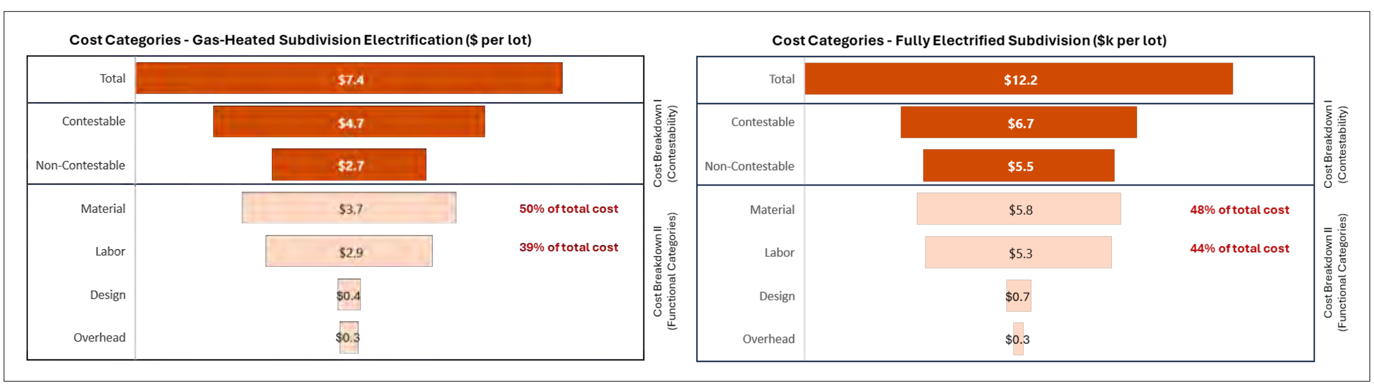



**Figure 11 - Breakdown of gas-heated and all-electric subdivision electrification costs ($k per lot)**

**Factors driving cost variances across LDCs:**

- **Economies of scale** - Feedback and observations from interviewing electricity distributors suggested that those with a broader scope and deeper electrification experience tend to exhibit lower cost disparities between fully electrified and gas-heated loads, where larger entities may benefit from reduced costs due to their size and operational efficiencies. Additionally, the accumulated expertise from extensive electrification projects is a likely contributor toward greater cost-effectiveness due to process efficiencies and design standardizations.

- **Design Standards:** An electricity distributor's current design and standards, especially around materials affect how much they would be impacted by a full electrification. For example, electricity distributors that do not already use larger cables needed for greater electrification see a greater variance in their electrification costs between 'all electric' and conventional, gas-heated loads, relative to electricity distributors which are already building with this transition in mind.

Examining subdivision electrification cost averages across each scenario supported the general observation and cost variance between lots based on the degree of electrification and nature of load, with an average variance of 10-13% from average electrification cost for both gas-heated and fully electrified scenarios (Figure 12). This higher variance to compared to primary line expansion costs suggests a greater sensitivity to cost contributors, such as variances in design standards in the case of subdivision electrification.

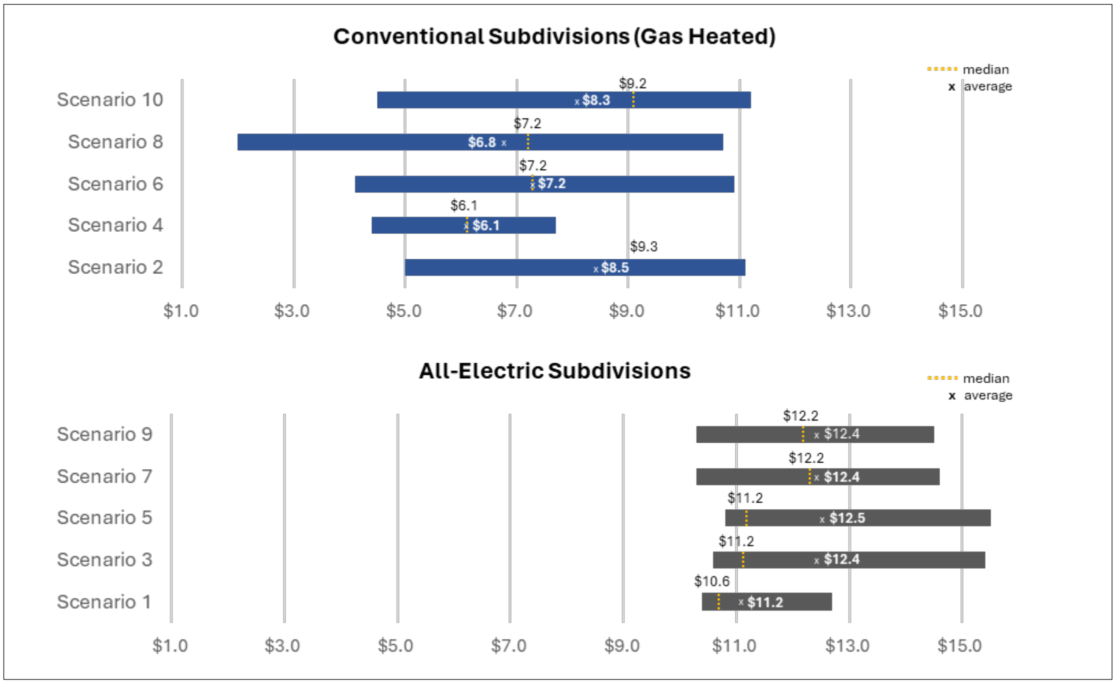



**Figure 12 - Cost averages across participating electricity distributors broken down by degree of electrification per scenario (costs in $K per lot)**

### *3.2.4 Cost Components Compared to the OEB's Activity and Program-Based Benchmarking (APB) Report*

In addition to the cost/km and cost/lot data presented above, each electricity distributor was asked for a Bill of Materials, outlining the different materials that they would need for each scenario, including quantity and unit cost of each. The Bill of Materials only covered major material groups and not all materials that would be needed for each scenario. Additionally, information about key material prices were uncovered through discussions with electricity distributors. These findings will be compared to the findings from the Activity and Program-based Benchmarking (APB) report, where applicable, to benchmark the cost of major materials that support the primary line expansions and subdivision electrification.

In 2018 the APB initiative was created by the OEB with the purpose of "encouraging continuous improvement by rate-regulated electricity distributors… and increased regulatory efficiency." In 2019, the OEB and various consulted stakeholders selected 10 programs for the APB.[5] For the purpose of this report, we will be focusing on two Capital Expenditures (CapEx) categories classified as (1) Poles, Towers and Fixtures and (2) Line Transformers. These were selected based off the data that is available through the Bill of Materials and discussions from this study. This analysis is shared below; however, it is important to note that potential differences in what is included in the cost data that was collected for the APB report compared to this study is a limitation and may contribute to some of the variances that are observed.

**CapEx: Poles, Towers and Fixtures -** The APB report published the industry trend from 2018 to 2022 of the CapEx portions of Poles, Towers and Fixtures. Notably, the cost of these components increased ~$6.1 million per year, while the number of poles installed dropped by 333 per year over the five-year period. This corresponds to, "the total combined Poles, Towers and Fixtures CapEx for 52 distributors [increasing] by 1.84% [and] the number of poles installed [decreasing] by 6.15%" in the period of 2021 to 2022. This data indicated a $575 increase in the unit cost per pole per year, with an average unit cost of $11,202 per pole in 2022.[6] The average per pole unit cost collected through the feedback from the electricity distributors is, on the low range, $15,550 / pole, and on the higher range, $20,300 / pole. Changes, such as inflation between years or changes in material costs may have contributed to this variance.

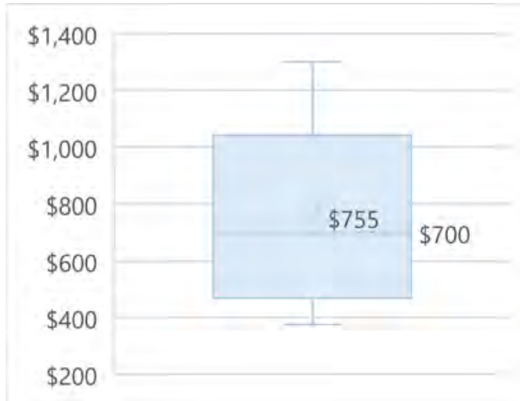
**CapEx: Line Transformers -** The APB Report also published data relating to line transformers. Notably, the cost of this component has increased ~$10.6 million per year, while the number of line transformers installed dropped by 641 per year over the five-year period. This corresponds to "the total combined line transformers CapEx for 52 distributors [decreasing] by 6.5% [despite the upward trend in the five-year period and] the number of line transformers installed [decreasing] by 20.2%" from 2021 to 2022. This data also highlights a $2,069 increase in the unit cost per line transformer per year, with an average unit cost of $13,771 in 2022.[6] From the Bill of Materials and information provided by electricity distributors, the average cost for a transformer was $7,898. Overall, this average is lower than the APB average cost / transformer. However, this average accounts for multiple types of transformers as each electricity distributor referenced different capacity transformers for primary line and subdivision electrification and relies on a smaller sample size than the APB report.

In summary, relative to the benchmarking report provided by the OEB, there are some variances in the cost per pole and cost per transformer based on differences, such as the type of material, changes in cost in the study periods, or different project specifications based off the scenarios provided to the electricity distributors. Relative to the benchmarking study, transformers seemed to have a lower cost on average than what was benchmarked; however, poles had a higher cost than what was benchmarked.

### *3.2.5 Basic Connection Costs*

Basic connection costs are one of the cost components that is covered by the electricity distributor and will be included in the rate base for cost recovery. These costs were included in the subdivision connection cost estimates provided in the sections and analysis above. The average basic connection cost across the electricity distributors surveyed was $755, with a range of approximately $375 to $1,300 per lot.

[5] Ontario Energy Board. *Activity and Program-based Benchmarking (APB) – 2022 Unit Cost Report (October 11, 2023).*
[6] Ontario Energy Board. *Activity and Program-based Benchmarking (APB) – 2022 Unit Cost Report (October 11, 2023).*




| | | |
|---|---|---|
| **Median** | $ | 700 |
| **Mean** | $ | 755 |
| **Min** | $ | 375 |
| **Max** | $ | 1,300 |

**Figure 13 - Basic connection cost ($ per lot)**

### *3.2.6 Electrical Utility Percent of Total Build Costs (Excluding Connection and Revenue Horizons)*

In surveys and conversations with the three builders/developers that were engaged in this study, the cost to provide electricity service to each unit was ~$5,000 - $10,000 in a subdivision. This corresponds to the average cost of $9.0K per lot uncovered in our assessment of electricity distributor data. This data focuses solely on the total build cost and does not consider the connection or revenue horizon. Developers noted that, other utilities, such as gas and telecommunications, rarely cost the developers anything to complete the work, as these utilities typically cover their portion of any trenchwork or installation.

According to an Altus report, the average price per square foot for the build cost of a non-custom home in the GTA is $210 to $285 for a single-family residential build with an unfinished basement.[7] In the scenarios presented in Appendix 2, the average house size is approximately 1,800 square feet. This leads to an average build cost of $378,000 to $513,000. Table 1 below showcases a summary of the percent of the build cost that new connections make up, specifically for gas heated and all electric new connections.

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Gas Heated | Low | $378,000 | $7,475 | 2.0% | $11,266 | 3.0% | $3,333 | 0.9% |
| | High | $513,000 | $7,475 | 1.5% | $11,266 | 2.2% | $3,333 | 0.6% |
| Fully Electrified | Low | $378,000 | $12,167 | 3.2% | $12,385 | 3.3% | $11,888 | 3.1% |
| | High | $513,000 | $12,167 | 2.4% | $12,385 | 2.4% | $11,888 | 2.3% |

**Table 1 - Electrical Utility Percent of Total Build Cost**

In summary, the average subdivision new connections cost per lot for gas heated developments makes up 1.5% to 2.0% of the average build cost of a single-family residential build. The average subdivision new connection cost per lot for all electric developments makes up 2.4% to 3.2% of the average build cost. This does not include the cost for the primary connection. As noted in our discussions, a variety of factors impact the percentage of the cost of developing a subdivision that utilities make up, such as the specific scope and conditions for each subdivision. Overall, the cost of electrical new connections comprises a small portion of the overall cost of developing a subdivision.

[7] Altus Group. *2024 Canadian Cost Guide.*

### *3.2.7 Feedback from Electricity distributors and Builders/Developers Regarding Costs and Schedules for New Builds*

During the discussions with and through the survey responses from electricity distributors and builders/developers, some key areas of variation, concern and opportunity have been identified. These insights are shared below. The qualitative insights that were gathered provide additional context to the variances in the data and examine other areas, such as timelines and sources of delays.

**Observation #1: Electricity distributors in Ontario have variations in how they manage core cost components, and differences in their processes.**

While some similarities exist across electricity distributors, there are also some key differences which may contribute to cost variances and result in different customer experiences when collaborating with each electricity distributor. Some of these differences may also affect timelines. While it was stated that some of these factors are not currently impacting timelines, as development accelerates, challenges that were identified may become exacerbated.

- **Materials:** Some electricity distributors highlighted that they wait to order materials until payment is received. Other electricity distributors highlighted that they do pre-order some materials with longer lead times or that are unique to their organization, while ensuring not too much stock is kept in inventory. The differences in how materials are procured may explain some of the variances in costs. While electricity distributors flagged that this is not impacting their timelines yet, as demand and speed of construction grow, the material lead times may contribute to additional delays.

- **Design and Construction Process:** For both the primary line and subdivision design process, some electricity distributors highlight that design work is typically contracted out, while others complete designs internally or use both methods, depending on the availability of their internal resources. This trend was similar for construction in the primary line with some electricity distributors completing the work internally, contracting it out or using a mix of both. For subdivision construction, the majority of electricity distributors used contractors to complete this work, while others used internal resources or a mix. This is important to consider as the mix of resourcing may impact labor costs for projects based on the cost of working with contractors relative to internal labor, contributing to cost variances across electricity distributors. Please note that contracting out in this context does not refer to the alternative bid approach. This refers to when an electricity distributor is conducting the work and uses their own contractors to support completion of the work.

- **Standards and Process Differences:** In an interview with builders/developers, it was flagged that the Ontario electricity distributors may have different standards, such as unique material specifications that may exist for one electricity distributor compared to another. Certain utility contractors that developers collaborate with may not have the buying power for specific materials or the experience with work in that specific territory, so different contractors with the necessary experience and knowledge of the electricity distributor's standards will need to be employed. While this was not cited as having a large impact on the builder/developer, it was stated that more commonalities would be helpful. Beyond material specifications, one of the differences that was most impactful was the completion of joint trench work. When electricity distributors create a trench to complete underground infrastructure construction, some electricity distributors will not allow gas or other utilities to share that trench. As a result, this impacts timelines and creates additional complexity for planning and executing the construction. It was also noted that there are differences in electricity distributors' offers to connect and response times. This can create variances in the customer experience, potentially impeding development in different service areas, and can impact timelines if response times are too slow.

**Observation #2: Timelines, and labour and material availability and cost, are considered an area of concern as development begins to accelerate.**

Electricity distributors in Ontario noted that they have seen increases in material costs and lead times for major material categories, such as cables and transformers, among others. While the cost of materials is already contributing to increased project costs, the lead times are not impacting timelines for all electricity distributors.

However, it was flagged that, as the number of new connection requests quickly increase, it may affect the supply of specialized labor and/or materials. This will not only create shortages that may contribute to even more increases in cost for the electricity distributors and, in turn, the builders/developers, but will also impact timelines for completing construction.

- **Labor:** Constructing and installing new infrastructure that meets the various electricity distributor standards and requirements is a specialized skill. As a result, there are only a certain number of skilled contractors and resources available for electrical distributors to collaborate with. If all electricity distributors have increased demands and are leveraging the same pool of labor, there may be a labor shortage. This not only impacts the timelines of new connections but may also impact cost as electricity distributors may need to start working with contractors who have a higher cost.

- **Material:** As the demand increases for materials across a variety of electricity distributors, material lead times may increase even more, ultimately impacting their availability and, in turn, new connection timelines. This may also increase the cost of a new connection as delays may occur and the cost of materials may rise as shortages become more prominent.

**Observation #3: Electricity distributors and builders/developers have begun to collaborate efficiently, finding channels for feedback with each other. However, uncertainty and changes on the demand side are an area of concern for electricity distributors and room for improvement in collaboration still exists.**

Currently electricity distributors and builders/developers engage in meaningful conversations to support planning and enhance efficiency in their collaboration and processes. The majority of builders/developers that were engaged highlighted that they are working with electricity distributors to understand who to speak with to answer certain technical questions so that they are better able to solve problems. In some instances, artifacts, such as 5-year plans, are shared so that electricity distributors can complete plans and identify any constraints early on. Additionally, the majority of electricity distributors shared that they currently have regular touchpoints with developers to gather feedback and determine areas that can be improved upon. However, it was noted that future planning meetings and discussions should take place more often to help provide electricity distributors with visibility into subdivision plans before approvals are complete, and that electricity distributors can more proactively create plans to match policies and information shared by municipalities.

In terms of areas of opportunities, electricity distributors shared that uncertainty and constant changes are impacting their processes. One area of opportunity that was highlighted is that designs change as municipalities provide feedback on developer submissions and market demands change, creating uncertainty and rework for electricity distributors. This may impact costs and timelines as more time is taken for design changes. Similarly, zoning laws and changing demand creates a need for upgrades to existing infrastructure, creating rework efforts that tie up labor. On the builder/developer side, it was mentioned that due to lengthy new connection timelines, designs are shared in a preliminary state and changed. In order to provide finalized plans, the timelines for new connections would need to be reduced. Electricity distributors have also shared that reduction in timelines is a piece of feedback they receive in their communications with developers.

In summary, builders/developers and electricity distributors that were engaged are beginning to enhance collaboration forums to share feedback and find areas of improvement. An opportunity for these communication and collaboration forums to become more robust was noted, particularly in the area of planning and forecasting so that both builders/developers and electricity distributors know what to expect. However, the uncertainty on the electricity distributor side and the timeline concerns from developers can create a cycle of rework. This can impact costs for electricity distributors as they must conduct redesigns.

**Observation #4: Distribution capacity constraints are of significant concern.**

In a conversation with builders/developers, it was flagged that an area of significant concern is distribution capacity availability for new connections. As electrification is pursued and development is ramped up, capacity in the distribution system is quite scarce for some of the electricity distributors. Compounding the impact of the increasingly scarce distribution capacity are previous guidelines that assign the cost of capacity increases to the first developer to require an expansion. This creates a first mover disadvantage and acts as a significant barrier to development.

In discussions with the electricity distributors and through the survey, they also agreed with this distribution capacity concern. Electricity distributors may encounter difficulties pre-emptively increasing their capacity considering the information provided in the Distribution System Code (DSC) which serves to protect ratepayers. As a result, distribution capacity is increased in a just in time environment, which not only has the potential to delay development timelines by multiple years as they build additional capacity, but also increases the cost to the customer.

**Observation #5: There are multiple other factors that contribute to timelines and cost; utilities are not the bulk of it.**

In discussions with builders/developers, it was highlighted that there are many other factors contributing to development timelines and costs. For example, the timelines for planning and execution across municipalities, securing permits for development, availability of finance from investors, and even weather variations in Canada were all shared as impactful to the timelines for new home development and the costs. It was also mentioned that in builder/developer collaboration with electricity distributors in Ontario, when distribution capacity is available for new connections, work with electricity distributors can be efficient. Some electricity distributors flagged that some market changes, such as slower sales or lack of investment, and denials from municipalities also play a role.

## 3.3 Limitations

The observations above provide insight as to which factors affect cost, where variances exist and some of the reasons for those variances. Given the scope of the study and the data collected, some limitations and additional considerations exist:

1. **Estimates vs. Actuals:** During this study, historical actual data for previous project new connection costs were not examined. Electricity distributors were asked to provide cost estimates for the purpose of this study. While standard reference scenarios and assumptions were provided to gather comparable data from the electricity distributors, these cost estimations were derived in different ways depending on the electricity distributors' current cost estimation processes.

2. **Time Horizon of Data:** The focus of this study was to gather cost estimates for various residential subdivisions. However, the data collected was not time series data and, as a result, does not provide information on trends or forecasting for future costs.

3. **Varying relevance and assumptions for the electricity distributors:** Throughout the data collection processes, electricity distributor participants flagged that not all of the reference case scenarios provided were as applicable in their region, given the size and landscapes in their regions. As a result, some assumptions were made by the electricity distributors, and costs were scaled up from similar scenarios to derive the cost estimates. These differences in estimation methodology and assumptions may have contributed to some of the variances seen.

4. **Some data was not available:** Some of the scenarios that were not relevant to electricity distributors were not able to be estimated due to lack of experience or relevance for that particular scenario. In some cases, we were unable to scale up costs from similar scenarios to provide cost estimates. Therefore, some scenarios had a smaller sample size of data.

5. **Sample sizes and build focus:** This study focused on residential subdivisions and gathered data and survey responses from six electricity distributors, and three builders/developers. However, many more electricity distributors and other residential builds, such as condos, exist in Ontario. This limitation was largely addressed by gathering data from electricity distributors who cover a large number of new connections and nearly half of the target new home builds.

6. **Scope of the study:** This study and the cost estimates only focus on the primary line and subdivision electrification costs. While system expansion concerns were noted in the qualitative research conducted, system expansion and distribution capacity costs and timeline research were not in scope for this study.

# 4. Industry Analysis

In addition to the growth in housing developments, there are many macroeconomic factors and changes in the utility industry that are impacting Ontario electricity distributors. These factors not only contribute to the costs and timelines of new connections, but also increase the demands placed on local utilities to manage and support multiple ongoing priorities. In order to understand these factors and their impact on the electrical distribution system, publicly available data was gathered and reviewed on three topics:

- 4.1. Net-Zero Trend and Electrification
- 4.2. Climate Resilience and System Hardening
- 4.3. Labor and Material Supply and Cost

These trends were examined as they are top of mind changes in the industry, and are expected to have impacts on demand, standards, timelines and, ultimately, costs of new connections. This section explores these trends and their impacts.

## 4.1 Net-Zero Trend and Electrification

In order to combat the effects of climate change, Canada is aiming to reach net-zero emissions by 2050.[8] As part of this goal, Canada has made a push for electrification within the utility industry. Notably, this will impact the generation and transmission of utilities as different and more renewable energy sources are developed and connected to the grid. However, this will also have a major impact on the demands and grid infrastructure of the distribution system.[9]

As electrification increases, electricity demand is also projected to rise. A report by the Independent Electricity System Operator (IESO) highlights that, in regards to electricity in general, “the demand forecast continues to show steady demand growth year over year, with total demand increasing 60 per cent over the next twenty five years.”[10] Consequently, there needs to be an increased capacity across the electrical system, which must be supported by upgrading infrastructure, strategically expanding the distribution system, and incorporating efficient energy use tools/tactics to manage demand.[11]

This will have multiple implications for electricity distributors in Ontario and energy distributors across Canada. Currently, gas is used as the primary heating source in residential subdivisions. However, as a result of electrification, developers are now factoring in components, such as electric heating and electric vehicle chargers. As a result of these changes in Ontario, electricity distributors will need to update their design and construction standards to meet the increased electricity demand, leading to additional costs and complexity when developing new connections, or upgrading distribution infrastructure. While fully electrified subdivisions, where gas is phased out and electricity is the primary source of energy, are uncommon, electricity distributors in Ontario highlighted that electrified subdivisions are estimated to contribute to a 20% to 50% increase in new connection cost. This estimation varies between electricity distributors based on the differences in the current state processes and variations in the material costs. Additionally, electricity distributors flagged the increased need for certain types of materials, such as larger cables and more transformers, to account for additional electricity demand and service fully electrified subdivisions. Their needs for specific types of material differ among electricity distributors based on the differences between their current state standards and what is needed for electrification.

Electrification will also impact electricity distributors’ infrastructure expansion and modernization plans, as distribution capacity constraints may increase with the growth in electricity demand. In Ontario, the OEB is working to address modern grid elements and electrification through various studies. For example, the OEB has created the Electric Vehicle (EV) Integration Initiative, examining areas such as the connection process of distributed energy

[8] Government of Canada. *Net-zero emissions by 2050.*
[9] Government of Canada. *Powering Canada Forward: Building a Clean, Affordable, and Reliable Electricity System for Every Region of Canada.*
[10] Independent Electricity System Operator. *Annual Planning Outlook - Ontario’s electricity system needs: 2025 – 2050.*
[11] Canadian Climate Institute. *Bigger, Cleaner, Smarter: Pathways for Aligning Canadian Electricity Systems with Net Zero.*

resources (DERs) and any related barriers, among others.[12] The OEB also conducted a Framework for Energy Innovation (FEI) Consultation on DERs. DERs are one of the innovations in the energy industry that help reduce the load on the distribution system to support initiatives, such as managing increased demand and reducing expansion costs.[13] The OEB conducted this consultation to "clarify the regulatory treatment of innovative and cost-effective solutions, including DERs and facilitate their adoption in ways that enhance value for consumers." This study examined three key areas of the DER integration into the distribution system: Benefit Cost Analysis Framework for DERs acting as a substitute for wires, utility incentives and DER integration. Some of the key conclusions to support cost effectiveness and integration included: a Benefit Cost Framework that holistically examines the impact of DERs on the system so that distributors can build a case for rate applications and wire substitution; using a deferral account for DER integration costs; and the plan to conduct another OEB initiative to clarify regulations for DER integration.[14] Grid modernization and innovation is essential to consider and seamlessly integrate into the existing grid as it allows for more distribution capacity to be available, supporting increased demand in a timely, cost effective way.

In summary, the push to electrification may impact the cost of new connections as the grid infrastructure must be more robust and may need to be upgraded.

## 4.2 Climate Resilience and System Hardening

Climate resilience refers to "the ability of the electricity distribution network to respond to high-impact, low-frequency disruptions by adequately preparing for, withstanding, rapidly recovering from, and adapting to these events… [this includes] activities prior to and following a disruption."[15] As more extreme weather occurs due to climate change, grid infrastructure can be damaged, and service may be disrupted. This is closely tied to electrification. As more people rely on electricity, disruptions may have a greater effect. One notable opportunity for utilities to become climate resilient while moving towards a net zero environment is the concept of hardening infrastructure. This includes changing design standards to procure and install more robust materials.[16]

Electricity Canada published their point of view on the electricity and utility sectors' roles in preparing and responding to climate change-induced changes, citing the importance of system hardening to "[ensure] safe, reliable, and affordable electricity for customers."[17] Bolstering distribution system to reliably meet the electricity demands is essential. Without the necessary preparation for the disruptions caused by climate change, the dependability of the electricity system may be impacted. The Climate Institute of Canada highlights that developing a resilient system can "eliminate a significant percentage of costs associated with damage that would have occurred in the absence of such adaptation measures,"[16], highlighting the importance of these measures for distribution companies.

In summary, climate resilience and the push to net-zero and electrification share commonalities. As system hardening and resilience become key goals to support the increased demand of electricity and reduce climate related system disruptions, distribution companies will need to evolve their material and design standards or operational strategies. This can, in turn, increase the cost of developing new connections as the distribution grid is upgraded.

## 4.3 Labour and Material Supply and Cost

As system hardening, infrastructure upgrades and extensions occur in the distribution system, there may be an increase in demand for certain materials and labour. The goal to quickly increase the supply of homes in Ontario will also add to this demand. As demand grows, there is an increased risk of shortages and, in turn, increased costs and lead times for material and labor, impacting the goal of accelerating housing development. It is essential to understand these macroeconomic trends, and to consider their impact on upcoming initiatives.

### *4.3.1 Labour Supply and Cost*

[12] Ontario Energy Board. *Electric Vehicle Integration.*
[13] Independent Electricity System Operator. *Distributed Energy Resources.*
[14] Ontario Energy Board. *Framework for Energy Innovation: Setting a Path Forward for DER Integration.*
[15] Ontario Energy Board. *Improving Distribution Sector Resilience, Responsiveness and Cost Efficiency.*
[16] Climate Institute of Canada. *Enhancing the resilience of Canadian electricity systems for a net zero future.*
[17] Electricity Canada. *Climate Change Adaptation.*

A survey conducted by the Ontario Chamber of Commerce (OCC) showed that 68% of Ontario organizations are experiencing labour shortages. This survey also identified “heightened job vacancies in the construction sector.”[18] Labour shortages, particularly within construction, may present challenges as businesses struggle to attract, upskill, and retain talent that is required to support the quick and large-scale development of homes. Furthermore, the Economic Policy Directorate (EPD) of Employment and Social Development Canada (ESDC) published a 10-year national labour market forecast, identifying labour trends. In this report, electrical engineers were identified as “showing strong signs of structural shortages,” indicating a longer-term labour shortage for this field. Electricians (excluding Industrial and Power System) are expected to experience shortages between 2022 to 2031. Some fields, such as construction, experienced frictional shortages, meaning that they would only have a short- or medium-term shortage. However, not all new connection construction fields are identified as having shortages.[19] While not all labour categories will experience long-term shortages, the shortages that do exist may impact the ability for Ontario-based utilities to find the adequate specialized skillsets and resources needed to design or connect electricity infrastructure, particularly as development demand increases. Ultimately, these labor shortages may impact development timelines and the shortage may impact costs as construction ramps up.

In terms of cost, the Construction Union Wage Rate Index, demonstrated a moderate increase in wages across construction trades from 2015 to 2023.[20] While these increases have been moderate, it is critical to consider the shortage of labour supply that may impact cost and pose significant challenges over the long-term.

### *4.3.2 Material Supply and Cost*

With the increase in demand for housing new connections follows an increasing demand for various materials needed to complete those connection requests. To support new connection costs, the goal of accelerating housing development and supporting affordability, utilities need to be able to secure materials in a timely fashion and at a relatively consistent, low cost. Factors, such as the climate and economic and political changes, impact global supply chains.[21] These factors, in addition to changes in the industry, such as electrification and climate resilience, can impact the supply and, in turn, price of some of the core materials that utilities need to support new connections. This section examines the supply of copper, aluminum, wooden poles and transformers. While these materials do not represent a comprehensive list, it showcases trends for a few of the major materials that are required.

**Copper:** Copper is one of the core raw materials needed to develop the cables that conduct electricity throughout the distribution system. According to the International Energy Association, “using average prices over the past 10 years, copper… costs are estimated to represent around 14%... of total grid investment.”[22] Additionally, the cost of copper, while it fluctuates quite a bit, has increased overall. The average monthly price per tonne of copper increased approximately 24.85% from 2018 to 2022.[23]

Copper supply is also of concern and is predicted to have an impact on the price. Projections suggest that there may be a copper supply shortage in upcoming years. One article stated that, while production capacity may reach up to 27 million tonnes per year by 2030, demand could reach up to 35 million tonnes, creating a shortage. In addition to increasing demand, the supply of copper is constrained due to factors, such as current copper mines producing lower quality copper and regulations impacting the ability to develop new mines quickly.[24] Another article shares a similar projection, with a “4.9-million-tonne copper supply shortfall by 2027 [which] may push prices up by 20%.”[25] For electricity distributors primarily using copper based wires, this will impact the timelines and cost of cable procurement.

[18] Ontario Chamber of Commerce. *Home Stretched: Tackling Ontario’s Housing Affordability Crisis Through Innovative Solutions and Partnerships.*
[19] Government of Canada. *Canadian Occupational Projection System (COPS): Imbalances Between Labour Demand and Supply (2022 – 2031).*
[20] Statistics Canada. *Construction union wage rate index, percentage change, monthly.*
[21] PwC. *The smart moves your supply chain needs now.*
[22] International Energy Association. *Mineral requirements for clean energy transitions.*
[23] Government of Canada. *Copper facts.*
[24] Globe and Mail. *Predicting copper shortage, major cable supplier urges increased recycling.*
[25] Canadian Mining Journal. *Copper prices may jump 20%, aluminum by 36% as demand outpaces supply: forecast.*

**Aluminum:** Aluminum is an essential raw material used in cable and wiring in the utility industry. According to the International Energy Association, “using average prices over the past 10 years… aluminium costs are estimated to represent around… 6% of total grid investment.” Aluminum is considered a cheaper substitute to copper.[26] However, like copper, the price of aluminum has increased overall,[27] and its supply is also predicted to be strained. One article shares estimates that demand could reach up to 108.2-million-tonnes by 2027, driven by demand from utilities and the automotive industry, among others. This could contribute to a shortage, with projections showing that there may be a “30.7-million-ton aluminum shortfall [by 2027] despite a 10% production increase over the same period.” This could lead to a 36% increase in prices compared to 2023.[28] For electricity distributors using aluminum-based materials, this will impact timelines and costs for material procurement.

The Industrial Product and Raw Materials Price Index from Statistics Canada shares general trends in the price of metals, ores, concentrates and scraps. As of April 2024, this index has reached 149.2, representing a 49.2% increase in price relative to the base period of January 2020.[29] This is showcased in Figure 14 below.

**Wooden Utility Poles:** Wooden utility poles are used in the distribution network to hold up cables for overhead connections. However, multiple factors have impacted the supply of this material. As electrification continues to be implemented, grid upgrades and system hardening will become necessary. This may increase the demand on wooden utility poles as electrical distribution companies extend and enhance connections to meet growing electricity needs. Additionally, increased volatility in the weather leading to floods or wildfires, among other natural disasters, can damage the poles and other materials. As utilities work to fix and replace the damaged infrastructure, demand for poles will increase. Finally, supply chain changes and disruptors, such as the pandemic and changes to the wood quality are impacting the availability of wooden utility poles.[30]

In addition to the supply changes, the price of wood has also changed overtime. According to the Industrial Product and Raw Materials Price Index, logs, pulpwood, natural rubber and other forestry products reached a price index of 123.7 in April 2024, relative to the base period of January 2020, representing a 23.7% increase in prices.[29] This represents a moderate increase in prices relative to other raw materials used in electrical infrastructure. This is demonstrated in Figure 14 below.

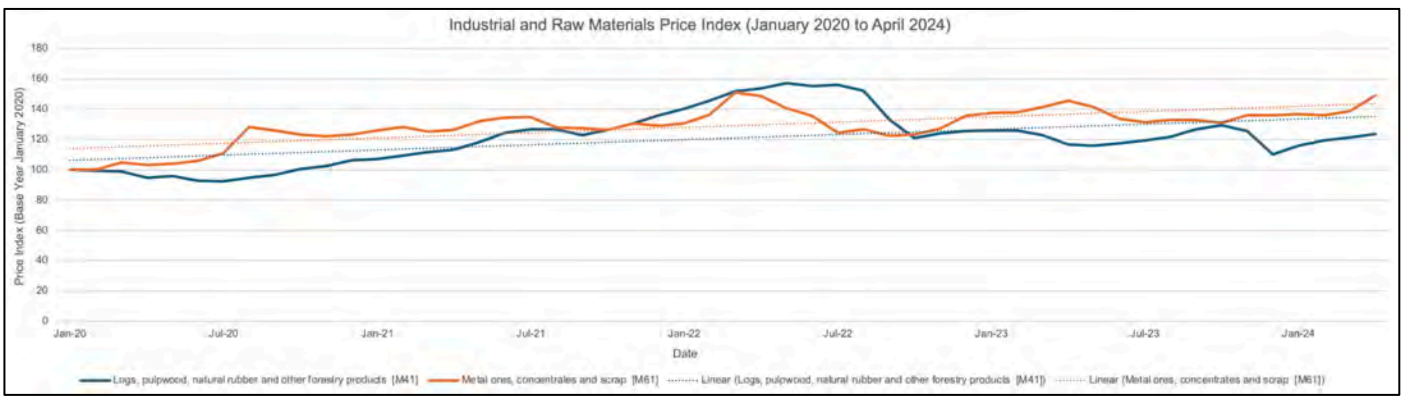



**Figure 14 - Industrial and Raw Material Price Index (2020 - 2024)**
Data Source: Statistics Canada Industrial and Raw Materials Price Index

**Electrical Distribution Transformers:** One of the key items in the distribution grid are transformers, which adjust the electricity voltage being sent through the system. In the case of distribution, transformers usually reduce the voltage coming in from the transmission system for user safety. This essential component of the distribution network has had a spike in demand, driven in part by grid upgrades and electrification, as more transformers or higher capacity transformers are needed to meet increased loads. One manufacturing organization, JFE, has “seen the greatest demand increase from residential distribution transformers and large power transformers.”[31] However, supply chain disruptions, such as the pandemic, have contributed to shortages that have impacted the lead times

[26] International Energy Association. *Mineral requirements for clean energy transitions.*
[27] Government of Canada. *Aluminum Facts.*
[28] Canadian Mining Journal. *Copper prices may jump 20%, aluminum by 36% as demand outpaces supply: forecast.*
[29] Statistics Canada. *Industrial product and raw materials price indexes, January 2024.*
[30] Electricity Canada. *Wooden distribution utility pole shortage.*
[31] AccessWire. *Canadian Manufacturer Doubling Production Capacity to Meet Surge in Electrical Transformer Demands.*

and price for materials like distribution transformers.[32] In regards to price, the Machinery and Equipment Price Index data highlighted that the price index of power, distribution and other transformers reached 169.2 in Q1 2024, an increase of 69.2% in price since the base period in 2016.[33] This is demonstrated in Figure 15 below.

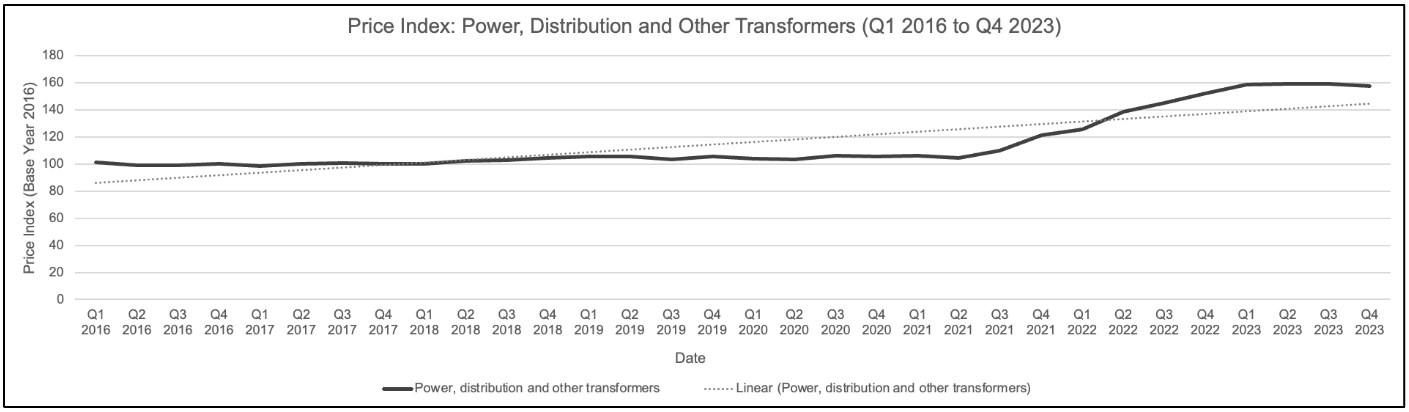



**Figure 15 - Price Index for Power, Distribution and Other Transformers from 2016 – 2023**
Data Source: Statistics Canada Machinery and Equipment Price Index

When comparing the price indices of materials in Table 2 below, it is evident that transformers and metal ores and scraps had the most change in their price index, with logs, pulp, natural rubber and other forestry products trailing slightly. Additionally, the change in the price index across all materials was greater than the change in the CPI (which is used in this case to represent inflation). This information highlights that changes in material prices may not have only increased due to inflation, but may be compounded by other factors, such as those above.

| *Category* | *Base Period* | *Jan. 2016* | *Jan. 2020* | *Jan. 2024* | *April 2024* | *% Change (2016 – 2024)* |
|---|---|---|---|---|---|---|
| *Metals, ores, concentrate and scraps* | Jan. 2020 | 79.8 | 100.0 | 136.7 | 149.2 | 87% |
| *Logs, pulp, natural rubber and other forestry products* | Jan. 2020 | 88.5 | 100.0 | 115.9 | 123.7 | 40% |
| *Power, distribution, and other transformers* | 2016 | 101.5 *(Q1 2016)* | 104.2 *(Q1 2020)* | 169.2 *(Q1 2024)* | N/A | 67% *(Q1 '24 - Q1 '16)* |
| *Consumer Price Index* | 2002 | 126.8 | 136.8 | 158.3 | 160.6 | 27% |

**Table 2 - Comparison of Price Indices and Changes in Price Indices Overtime**
Data Sources: Consumer Price Index, Industrial & Raw Materials Price Index, Machinery and Equipment Price Index

Discussions with and survey responses from Ontario electricity distributors showcased that these trends are impacting costs in Ontario new connections. Increased costs and lead times were cited for large materials, specifically transformers, cables, switchgears, poles and elbows. Additionally, costs of materials were highlighted as increasing the overall project costs. While material costs and lead times were the area where most changes have been observed by Ontario electricity distributors, labor has changed slightly in cost as well due to inflation and resulting contract rate increases. While material lead times have not had a major impact on timelines yet, and labor shortages are not widespread, accelerated housing development could exacerbate these problems. Evidently, supply shortages can lead to longer lead times for procuring materials and increased prices, impacting the timeline and costs of new connections.

[32] Government of Canada. *Canada Electricity Advisory Council – Interim Report.*
[33] Statistics Canada. *Machinery and equipment price index, by commodity, quarterly.*

# 5. Jurisdictional Review

The increased demand for housing across Canada leads to an increased demand on utilities to provide new connections and expansions efficiently and effectively – synonymous to the current situation in Ontario. Examining regions across Canada offers context on other approaches, policies and procedures that are used to support cost and timeline efficiency.

The jurisdictional review focuses on four provinces within Canada: British Columbia, Alberta, Manitoba and Québec. This section leverages publicly available information and information gathered through regulator discussions to generate insights on the differences in the subdivision new connection costs, strategies and policies. These have been summarized into the following three categories:

- 5.1. Guidance for Cost Estimation and Subdivision Development
- 5.2. Developer Programs and Automation
- 5.3. Strategies and Future Considerations

The information below does not provide a comprehensive review of all the information available across provinces, but rather highlights key distinctions relevant to the purpose of this report. Limitations for the use of this information in Ontario, specifically differences in Ontario's size and utility sector relative to other provinces, is presented in section 5.4.

## 5.1 Guidance for Cost Estimation and Subdivision Development

Overall, while standardized costs and timelines were not identified for all provinces, some electricity distributors do provide cost schedules. These cost guidelines create transparency and consistency in the subdivision electrification cost estimation and development process, contributing to a positive customer experience. As costs become clearer, customers experience less uncertainty and cost estimation timelines may be more efficient.

### *5.1.1 Cost Guidelines*

- **Hydro Québec** provides a cost table in Chapter 20 of their Conditions of Service, detailing the costs and charges associated with different materials and services. Figure 16 showcases a sample of some of the costs from their 2021 Conditions of Service. If the requested work does not fall under Hydro Québec's basic services, then, in some cases, these cost schedules can still be used, and the costs can be scaled up to calculate the estimated cost of work that customers will need to pay for subdivision electrification. Where these cost schedules cannot be used, Hydro Québec provides clear guidelines on how the cost is going to be calculated, including providing information about a Detailed Cost of Work Calculation in Section 9.1.2 and Schedule IV of their Conditions of Service.[34]

[34] Hydro Québec. *Conditions of Service, April 1, 2021, Edition.*

## 20.2 Prices for Major and Minor Work – System Extension and Modification

### Table II-A – Prices for Overhead Service Loops

| New *low-voltage service loop* – per job or per metre | | | |
|---|---|---|---|
| | Current rating of service box | | |
| Length of *service loop* | 200 A or less | 320 or 400 A | 600 A |
| 1 30 m or less | Included in *basic service* | Included in *basic service* | Included in *basic service* |
| **With additional pole** | | | |
| 2 Between 30 and 60 m | $1,760 | $1,880 | $3,460 |
| 3 Over 60 m: Fixed amount + price per metre | $1,760 + $35/m | $1,880 + $42/m | $3,460 + $76/m |
| **Without additional pole** | | | |
| 4 Price per metre applicable | $11/m | $18/m | $50/m |

| New *medium-voltage service loop* – per job or per metre | | |
|---|---|---|
| | Type of supply | |
| Length of *service loop* | Single-phase | Three-phase |
| 5 30 m or less | Included in *basic service* | Included in *basic service* |
| 6 Between 30 and 60 m | $3,550 | $3,990 |
| 7 Over 60 m: Fixed amount + price per metre | $3,550 + $59/m (price from Table II-B) | $3,990 + $76/m (price from Table II-B) |

**Figure 16 - Hydro Québec Conditions of Service Cost Schedule Sample**
Source: Hydro Québec Conditions of Service, April 1, 2021 Edition

- **BC Hydro** provides a breakdown of their costs available to access through their website. For design connection projects, including subdivisions, where infrastructure or capacity must be added, BC Hydro may charge a design deposit, extension fee, and/or standard charges. The detailed cost breakdowns are available on their website and a sample has been provided in Figure 17. Where applicable, BC Hydro also adds a Revenue Guarantee Fee. While the Revenue Guarantee Fees are not explicitly stated online, examples of how it is calculated are provided, which helps to provide transparency to customers. In the cases where infrastructure does not need to be added, standard connection charges are also shared on their website.[35]

[35] BC Hydro. *Costs for design connection projects.*

| AMPS | ZONE I | ZONE II & IB |
|---|---|---|
| Overhead service | | |
| New connection service | | |
| 100 | $799 plus GST | $1,110 plus GST |
| 200 | $838 plus GST | $1,149 plus GST |
| 400 | $1,207 plus GST | $1,560 plus GST |
| 600 | $1,882 plus GST | $2,306 plus GST |
| Relocation/alteration or disconnect/reconnect for electrical work (existing wire) | | |
| Up to 200 Amps | $860 plus GST | $1,171 plus GST |
| 400 Amps | $924 plus GST | $1,235 plus GST |
| 600 | $1,108 plus GST | $1,480 plus GST |

**Figure 17 - BC Hydro Sample of Standard Charges**
Source: BC Hydro – Charges and Fees for Electrical Connections

The clear cost guidelines, transparency and consistency in how costs are estimated sets clear customer expectations, enhances the overall experience and reduces cost variability for developers. It also allows customers to understand specific charges associated with their projects, enabling them to accurately assess and estimate their expenses. It is important to note that both BC and Québec have one major utility servicing a large portion of customers. However, Ontario has approximately 58 rate-regulated electricity distributors servicing different service areas, creating an added layer of complexity.

The initial review did not find similar standards or information for timelines. While timeline information is provided in certain instances on electricity distributors' websites in the four provinces, subdivision timelines were more difficult to clarify. Given the plethora of factors that impact timelines, and the added complexity for subdivision developments, timelines are more variable.

## 5.2 Developer Programs and Automation

Timelines are a major factor in new housing development and affordability across Canada and can impact new connection costs. Electricity distributors in other provinces, such as Manitoba and BC, have introduced developer programs and tools for customers to leverage for support during the subdivision connection process. Developer programs and automation tools that help streamline processes may be beneficial to accelerate or simplify subdivision connection processes, reducing barriers for developers and enhancing the customer experience. Through simplifying and streamlining the subdivision connection process it may in turn unlock cost and timeline efficiencies.

### *5.2.1 Development Programs*

- **Manitoba Hydro** offers a “Developer Choice Program” that enables developers to dictate their approach for subdivision development projects. Developers can select to follow the “Traditional Method”, whereby Manitoba Hydro manages areas, such as distribution design, utility coordination, and purchasing and installing materials, among others. In this approach, “the cost of this work is transferred to the developer with an investment from Manitoba Hydro.” In contrast, developers can choose to follow the “Developer Choice Program” approach, which enables the developer to manage the project, including design, utility coordination, and securing the necessary approvals, among others. In this approach, “the cost of the work is paid by the developer with an investment from Manitoba Hydro when the utility infrastructure is transferred to [them].” Developers are required to apply to be part of the program and must meet select eligibility criteria.[36] These programs allow customers greater flexibility and the opportunity to take charge on how they would like to manage the project and their timelines. This not only creates a positive experience for the developer, but also reduces the amount of time developers need to spend following up with distribution companies on tasks, streamlining and enhancing the efficiency of the process.

- **BC Hydro** offers the “Underground Electrical Service for Residential Construction” program in certain regions. Through this program, customers can engage with “BC Hydro-certified professional electrical engineering firms.” These entities can support in the design process and oversee construction for the underground infrastructure, ensuring it is aligned to BC Hydro’s standards and procedures. Participation in the program depends upon the customer’s location in BC and if they meet the eligibility criteria. BC Hydro states that this program can help “your project progress more efficiently, and therefore more cost effectively.”[37]

While these are similar to the contestable / non-contestable options that Ontario electricity distributors offer to their customers, these programs take it a step further. They allow customers to manage the entire project and seamlessly or quickly access contractors that meet the standards for that distribution company. This enables added efficiency for timelines and cost, and flexibility for customers.

#### *5.2.2 Automation and Tools Provided by Electricity Distributors Outside of Ontario*

Self-service tools serve to enhance the customer experience, efficiently provide information, and reduce the time required by employees on certain tasks. The efficiency and streamlined process can help reduce timelines and, in turn, enhance cost efficiency.

- **FortisAlberta** has enabled a cost estimator tool for primary services and basic investments on their website. While it is not comprehensive for all types of projects, it covers cost estimations related to residential, farm, oil and gas fields, irrigation sites, and commercial and general service types. Customers must first choose from a list of service types, add an address or a legal land description, and then place a pin on the map to showcase where the site will be. The estimator will then share a high-level cost range based on the location and length of the line from the nearest power lines / poles, as displayed in Figure 18. While these estimates are not comprehensive, it can serve as an initial estimate, helping customers determine if they want to pursue a formal request.[38] Providing customers with such a tool may help to free up the electricity distributor’s resources as individuals can decide whether or not to pursue the project before engaging with FortisAlberta. This can enhance the efficiency for processing formal requests that are submitted.

[36] Manitoba Hydro. *Developer Choice Program.*
[37] BC Hydro. *Customer build program.*
[38] FortisAlberta. *FortisAlberta Service Estimator.*

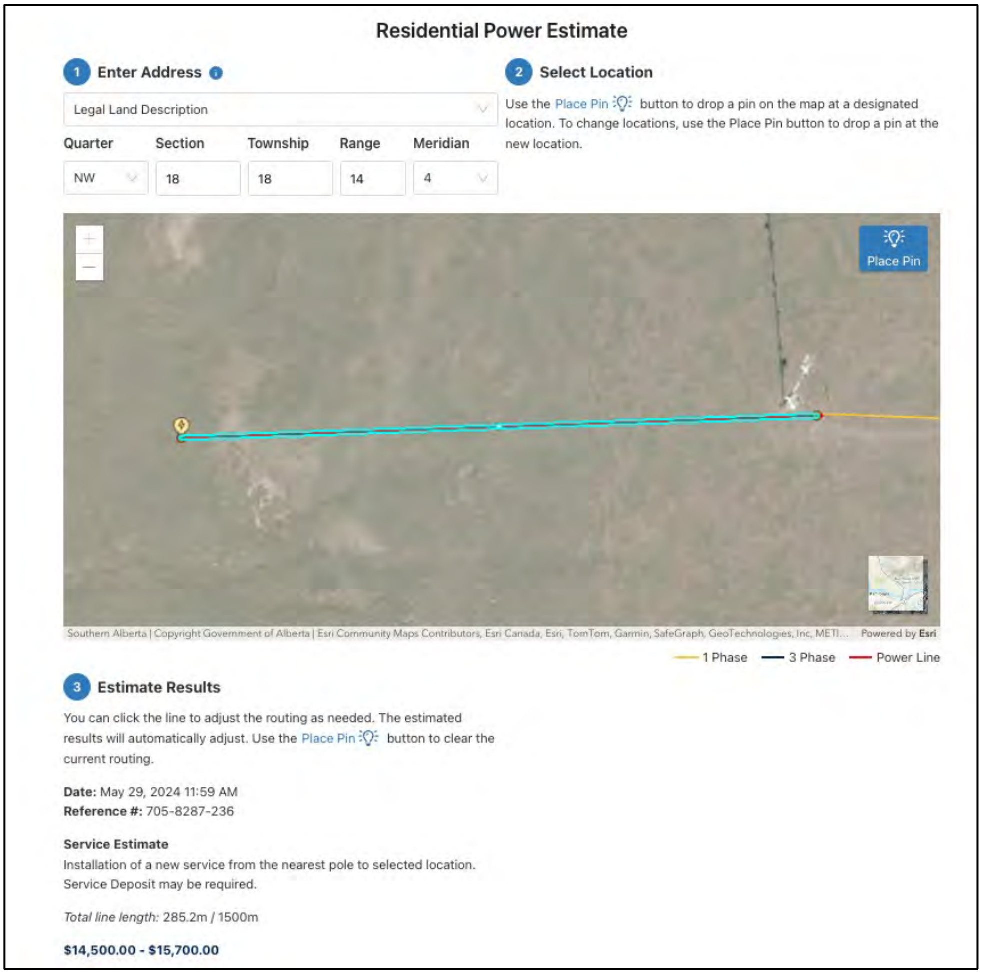



**Figure 18 - FortisAlberta Service Estimator Output Sample**
Source: FortisAlberta Service Estimator

## 5.3 Future Planning Across Provinces

The distinctions outlined in sections 5.1 and 5.2 are focused on the current state of each province's electricity distributors. This section looks into the future planning, strategies, and considerations across the provinces. Faced with similar challenges, such as population growth and the need for more efficiency in land development, the electricity distributors across the four provinces have outlined plans for updating processes and addressing delays in timelines.

### *5.3.1 Electricity Distributors' Strategies for Efficient Connection Timelines*

- **BC Hydro:** Most of BC Hydro's simple connections per year do not include design work, enabling them to complete the connection with a turnaround time of, on average, seven days, after securing permits. However, the distribution company is facing lengthier timelines for what they deem complex projects (which includes subdivisions) that need design work due to more requests being made, and staffing constraints. To reduce the connection timelines, BC Hydro is looking at introducing three key changes to their policies.[39]
  - *Resourcing and Training* – Increasing the staffing and training for new hires for the design and connection functions, while continuing to engage contractors where it makes sense to do so.[40]

[39] BC Hydro. *Improving customer connections for a cleaner future.*
[40] BC Hydro. *Improving customer connections for a cleaner future.*

- o *Process Improvements* – BC Hydro examined their design process to identify ways to enhance its efficiency, extracting and prioritizing recommendations in 2022. Since 2023, these recommendations are being implemented. For example, Design Lite has been implemented, which "reduces design effort for simple projects, helping to free up time for…designers to focus on more complex, higher risk projects thereby reducing customer connection timelines."[40]
- o *Improving the Customer Experience* – Revamping the customer intake process, enabling the team to gather better information and, in turn, accelerate design work. This can reduce timelines and, in turn, potentially unlock cost efficiency. Additionally, BC Hydro is looking to improve the self-service experience and provide early communication on any delays that are encountered during the connection process. This can enhance the customer experience, reduce the amount of contact with staff, and help customers gather information efficiently.[40]

- **BC Hydro:** In addition to directly addressing the timeline delays caused by increasing requests and staffing shortages, BC Hydro is also examining their distribution capacity and how that impacts timelines. It has been flagged that, in some high growth regions, there is not always enough distribution capacity, and these capacity enhancements are not occurring as quickly as load increases. This impacts connection and project timelines. To address this, BC Hydro has been:

  - o Increasing the number of feeders available and feeder planning
  - o Pre-emptively upgrading underground infrastructure to support increased loads
  - o Creating positions for spare feeders so that, where necessary, new feeders can quickly be added
  - o Sharing "capacity feasibility reviews" with major customers so that expectations are set early on

  These, in addition to other initiatives, are already underway to address distribution capacity constraints. By pre-emptively addressing this challenge and being able to quickly enhance distribution capacity, BC Hydro can reduce delays and accelerate timelines in their high growth areas, which may in turn reduce costs.[40]

- **Hydro Québec:** Hydro Québec has developed an Action Plan for 2035 for multiple areas of their organization. One key priority is improving their service quality, including, but not limited to, making new connection request processing and timelines more efficient. Since 2019, connection timelines have risen by ~70% due, in part, to the rise in the number and complexity of connection requests. The action plan indicates that Hydro Québec has been making changes to improve timelines, including "prioritizing work with the greatest impact for customers, simplifying request processing and standardizing equipment and work methods." Additionally, Hydro Québec is placing more emphasis on the customer experience, reducing the number of interactions with representatives, and improving transparency into a customer's connection requests online. All these efforts can support timeline reduction and, while the impact to more complex connections was not estimated, Hydro Québec estimates that these measures can reduce the average time to completion for their common work by ~40%.[41]

#### *5.3.2 Increased Standardization and Regulator Reviews*

- **Alberta Utilities Commission (AUC):** In their 2021 – 2024 Strategic Plan, the AUC highlighted "Facilitating change in the sector" as one of their primary objectives. To achieve this objective, the AUC aims to "Standardize (i) connection practices and processes among Alberta electric distribution utilities to ensure there are no barriers to entry for distribution energy resources and (ii) terms and conditions of service required by Alberta's distribution utilities to ensure customers receive consistent treatment." Additionally, the AUC aims to "[evaluate] the development of uniform distribution planning and reliability requirements to better coordinate distribution and transmission planning and ensure overall system optimization and control costs." The desired outcome will be to have "clear and comprehensive requirements that create certainty and consistency for market participants and promote efficient market outcomes."[42] During the period of 2021-2023, the AUC initiated consultations that focused on "standardizing and reviewing the costs for connection, disconnections and maximum investment levels for greenfield home construction."[43] Ultimately, these reviews can enable clearer connection costs and guidelines, and make way for grid innovations that can support increased distribution capacity.

[41] Hydro Québec. *Towards a Decarbonized and Prosperous Québec.*
[42] Alberta Utilities Commission. *2021 – 2024 Strategic Plan.*
[43] Alberta Utilities Commission. *2022 – 2023 Report Card.*

There are currently many interesting distinctions in the processes and programs that electricity distributors run across Canada to help support efficiency and effectiveness in new connection timelines and costs. In addition, distribution companies and regulators are re-examining policies and processes to reduce the barriers for growth in the future.

## 5.4 Limitations

The distinctions outlined above, and the future state strategies, can provide information on the programs and approaches that are being used to reduce timelines and enhance cost effectiveness of new connections in other provinces in Canada. While the research provides additional information and could be informative to the Ontario market, there are some limitations that need to be considered.

1. **Ontario's Population:** Ontario's population does currently, and likely will in the future, far surpass the other provinces' populations. As a result, while the percentage of growth in each province is comparable,[44] the scale of growth will differ.

2. **Different Utility Sector Structures:** The majority of provinces in Canada have one major utility, whereas Ontario and Alberta are disaggregated with a number of distribution companies serving different regions, with Ontario having a large number of electricity distributors across the province. As a result, best practices, approaches, and policies in these other jurisdictions may not be directly applicable to Ontario and must be considered in the context of Ontario's utility sector structure.

[44] Statistics Canada. *Population Projections for Canada, Provinces and Territories: Interactive Dashboard.*

# 6. Conclusion and Implications

Leveraging public research, cost data collected from a set of 10 reference scenarios and qualitative data gathered through surveys and discussions with six Ontario electricity distributors, three developers and one regulator, several observations and areas of opportunity were identified.

***Jurisdictional Initiatives to Accelerate Housing Development***

Various electricity distributors across provinces have implemented measures to accelerate their timelines and enhance cost efficiency to support housing development. For example, some electricity distributors have leveraged transparent, standardized costs, provided automation and self-service tools to customers, and developed programs to provide support in the new connection process. This may serve to streamline the process and timelines and create cost efficiency. Additionally, future strategies to support distribution capacity planning, create a positive customer experience, accelerate timelines and enhance standardization are being implemented. These strategies and approaches suggest practices and innovations being taken across provinces, but it is important to note that there are unique nuances that differentiate Ontario's utility sector from other provinces.

***Variances Exist Across LDC Costs, Processes and Customer Experience***

By examining the cost data, it was identified that costs across Ontario electricity distributors vary, with the construction type and electrification considerations being the most impactful sensitivity factors. Some of the variances noted in the average unitized overhead/underground primary line and all-electric/gas heating subdivision electrification costs are explainable through the various methodologies and design standards Ontario electricity distributors use to perform cost estimations and install new connections. Due to the nature of the cost estimation scenarios, some assumptions were made by Ontario electricity distributors which also contributes to some of the variances that were identified. However, some variances should be further explored, such as the variances in all-electric vs gas scenarios as more electricity distributors begin to experience electrification scenarios. Also, there are variations in processes and customer experiences among Ontario electricity distributors, which is expected in the utility industry. These include different material standards and procurement strategies, offers to connect, and response timelines.

***There are multiple areas of opportunity for accelerated housing development***

Areas of opportunity to efficient operations were identified in our surveys and discussions with builders/developers and electricity distributors. These include changes in designs leading to rework, concerns about the impact of accelerated development on the material and labor supply, and the increasing costs and lead times of materials. In addition, distribution network capacity constraints in the grid and a first-mover disadvantage for expansions necessary for greenfield development that is far from existing infrastructure were noted as concerns. This can significantly impact timelines and discourage developers from absorbing initial costs, inhibiting growth.

***Implications***

The challenges experienced by electricity distributors across Ontario have increased the cost of projects and may potentially contribute to additional costs for new connections, lengthier timelines and varying customer experience. While some of these factors are uncontrollable by electricity distributors, such as macroeconomic and industry trends, these challenges ultimately can impact the cost, acceleration and volume of housing development within Ontario. As the industry continues to change, continuous data collection can provide an understanding of the evolution of cost variances, drivers, and their impact, and support in determining paths to maintain cost efficiency. Considering factors, such as industry and macroeconomic trends, existing guidelines, and other factors that contribute to development cost and timelines, can provide a more comprehensive view of the new connection and development landscape.

# 7. Appendices

## Appendix 1: Glossary

- **Electricity Distributors / Distribution Companies:** Throughout this report, these terms are used to describe distributors who provide electricity to residential subdivision developments. In the Appendices below, these electricity distributors are referred to as Local Distribution Companies or LDCs.
- **Subdivision:** A residential land development where land is divided into smaller lots. Residential properties are then built on the lots.
- **Distribution Infrastructure:** This includes the infrastructure that makes up the distribution system, including distribution substations, poles and wires that transmit electricity to the subdivision, and transformers which adjust the voltage traveling throughout the system, among others.
- **New Connection:** Refers to the process of establishing the physical links between a newly constructed residential subdivision to an existing electrical utility grid.
- **Primary Line Expansion:** Involves bringing electricity to the subdivision from the distribution substation.
- **Subdivision Electrification:** Involves building electrical infrastructure within a subdivision to service each lot or home.
- **Capacity availability in the distribution network:** This refers to the capacity that is available at the distribution substation. Distribution substations that have enough capacity for the required loads of a new connection can be used when developing the primary line expansion. When capacity is not available at a substation, then a new connection cannot be serviced from that specific substation. Another substation with capacity may need to be used for the new connection or the system needs to be expanded. The costs associated with this are out of scope for this report.
- **System Expansion:** System expansion is defined as a "modification or addition to the main distribution system in response to one or more requests for one or more additional customer connections that otherwise could not be made."[45]
- **Greenfield:** These are developments on land that was not previously developed, requiring the extension of a primary line from the existing transmission network to the subdivision.
- **Brownfield:** Typically involves infill development on vacant or underutilized land within already developed urban areas, negating the need for new primary line expansions.
- **Overhead VS Underground:** Overhead refers to above-ground infrastructure, such as poles and wires, to transmit electricity. Underground connections refer to cables that run underground to service an area.
- **Contestable VS Non-Contestable / Alternative Bid:** Contestable work is work in the new connection process that can either be completed by the electricity distributor or a contractor hired by the developer, whereas non-contestable work must be completed by the electricity distributor or one of their contractors.
- **Basic Connection Cost:** Basic connection costs are one of the cost components that is covered by the electricity distributor and will be included in the rate base for cost recovery.

[45] Ontario Energy Board. *Distribution System Code*.

## Appendix 2: Cost Estimation Template for Ontario Electricity Distributors

In all, ten electricity distributors were contacted for participation in this study - Alectra, Hydro Ottawa, Elexicon Energy, Enova Power, London Hydro, Oakville Hydro, Burlington Hydro, GrandBridge Energy, Milton Hydro, and Essex Power. Below are snapshots of the data-capture template provided to each electricity distributor to gather their cost estimates for each of the reference case scenarios and to gather information on their bill of materials (BOM).

### 1. Scenario Inputs

| Scenario Inputs | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| # | Scenario | Build type | Lot type | Number of lots | House Size (sq ft) | Lot Size (sq ft) | Load Type / Usage | Distance to nearest takeoff point (km) | Primary Construction | Subdivision Construction | Energy Availability | Projected In-Service Date | Additional Context |
| 1 | New Upscale Community | Greenfield | Single Family Home | 50 | 2500 | 3600 | 200 A | 5 | Underground | Underground | All Electric (Water and Heating), Plus 2 EVs | 2024 | Primary expansion or brand new circuits |
| 2 | New Upscale Community | Greenfield | Single Family Home | 50 | 2500 | 3600 | 200 A | 5 | Overhead | Underground | Electric and Gas Hook-up | 2024 | Primary expansion or brand new circuits |
| 3 | New Upscale Community | Greenfield | Single Family Home | 200 | 2500 | 3600 | 200 A | 1 | Underground | Underground | All Electric (Water and Heating), Plus 2 EVs | 2024 | Primary expansion or brand new circuits |
| 4 | Houses Development Project | Greenfield | Semi-Detached Townhouses | 200 | 1800 | 3000 | 200 A | 10 | Overhead | Overhead | Electric and Gas Hook-up | 2024 | Primary expansion or brand new circuits |
| 5 | Houses Development Project | Greenfield | Semi-Detached Townhouses | 200 | 1800 | 3000 | 200 A | 5 | Overhead (Major road crossing 12 lane hwy) | Underground | All Electric (Water and Heating), Plus 2 EVs | 2024 | Primary expansion or brand new circuits |
| 6 | Townhouses Development Project (massive) | Greenfield | Townhouses | 500 | 1300 | 1500 | 100 A | 5 | Overhead | Underground | Electric and Gas Hook-up | 2024 | Primary expansion or brand new circuits |
| 7 | Townhouses Development Project (massive) | Greenfield | Townhouses | 500 | 1300 | 1500 | 100 A | 10 | Underground | Underground | All Electric (Water and Heating), Plus 2 EVs | 2024 | Primary expansion or brand new circuits |
| 8 | Townhouses Development Project (massive) | Greenfield | Townhouses | 1000 | 1300 | 1500 | 100 A | 5 | Overhead | Underground | Electric and Gas Hook-up | 2024 | Primary expansion or brand new circuits |
| 9 | Townhouses Development Project (massive) | Greenfield | Townhouses | 1000 | 1300 | 1500 | 100 A | 5 | Underground | Underground | All Electric (Water and Heating), Plus 2 EVs | 2024 | Primary expansion or brand new circuits |
| 10 | Established Residential Houses Neighborhood (including WWI Scenarios) | Brownfield (density increase) | Semi-Detached Townhouses | 40 | 1500 | 1500 | 100 A | 0 | | Underground | Electric and Gas Hook-up | 2024 | No expansion (Replace 5 existing 2100sqft homes with 100A connections on 60x120 lots with 40 new townhomes)<br>Some upgrades to existing network |

### 2. Requested Outputs

| LDC Outputs > | I. Cost for Primary network expansion / connection to Subdivision | | | | | | | | | II. Cost of Electrifying Subdivision | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Cost - Primary Line Expansion / Subdivision Connect | 1. Roll-up by Contestability | | 2. Roll-up by Functional Categories | | | | | | Cost - Subdivision Electrification | 1. Roll-up by Contestability | | 2. Roll-up by Functional Categories | | | | | |
| Total Cost | | Contestable | Non-Contestable | Materials | Labor | Design | Overhead | Contingency | | | Contestable | Non-Contestable | Materials | Labor | Design | Overhead | Contingency | Streetlighting |
| 0 | | | | | | | | | BOM per Scenario<br><br>Please list out:<br>1. Material list<br>2. Quantity<br>3. Cost broken down by functional categories (material, labour, overheads) | | | | | | | | | |
| 0 | | | | | | | | | | | | | | | | | | |
| 0 | | | | | | | | | | | | | | | | | | |
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### 3. Additional Questions

| III. Overall | | IV. Additional Context Requested | | | |
|---|---|---|---|---|---|
| Estimate Class Used (AACE Standard) | Capital Contribution Calculation | Primary Construction: *If underground do you use direct bury or duct bank?* | Primary Construction: *Confirm number of phases and how you make that decision* | Subdivision Construction: *What is the peak planning load that is assumed per premise?* | Subdivision Construction: *Does the peak planning load assumption change based upon panel size?* |
| | | | | | |
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| | | | | | |
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| Additional Questions | |
|---|---|
| Subdivision Construction: What infrastructure changes would be required if each premise had 2 EVs, or in the scenarios where EVs are considered, those EVs were removed. | |
| Subdivision Construction: What organization (ex: Municipality, Developer, LDC) covers the cost for streetlighting? | |
| Basic Connection Cost | |

### 4. Bill of Materials

| | | | | | | Installation Costs | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Reference Model Scenario | Line Extension, or Electrifying Subdivision | Material Name | Material Description | Quantity | Units | Unit Cost | Unit Labour Hours | Unit Wage Rate | Unit Overheads | Total Unit Cost | Total Cost |
| | | | | | | | | | | 0 | 0 |
| | | | | | | | | | | 0 | 0 |
| | | | | | | | | | | 0 | 0 |
| | | | | | | | | | | 0 | 0 |
| | | | | | | | | | | 0 | 0 |

## Appendix 3: Stakeholder Interview and Survey Guides

| | |
|---|---|
| Current LDC Collaboration | Are there particular LDCs that you work with more regularly? |
| | What is currently going well in your collaboration with Ontario LDCs and your approach to subdivision development? |
| | Are there any notable differences between the LDCs that you work with? |
| | Do you find it more difficult to work with Ontario LDCs than you do with other utility companies across the province and elsewhere? Why or why not? |
| | Do you feel that there is adequate communication and collaboration between your team and the LDCs you work with in Ontario? Why or why not? |
| | Are there any areas of opportunity that you've identified in your work with Ontario LDCs when you are developing subdivisions? |
| | If you work in other jurisdictions, outside of Ontario, how does your work / collaboration with LDCs outside of Ontario differ from your work with Ontario LDCs? |
| | If you have worked in other jurisdictions in collaboration with LDCs, what worked well and may support your work with LDCs in Ontario? What hasn't worked well? |
| General Information on Subdivision Development in Ontario | Currently, what percentage of the cost do utilities make up for developing a subdivision? |
| | What percentage of the utilities cost for subdivision development is attributed to 1) electricity and 2) gas? |
| | On average, what is the approximate cost of each utility type per lot in a subdivision in Ontario? For example, what is the average cost of electricity per lot in a subdivision? |
| | How does the process of connecting electricity differ from connecting the other services, such as water, telecommunications, or other utilities? |
| | How long does it typically take to develop a subdivision in Ontario? |
| | What factors impact that timeline, if any? Do LDCs impact that timeline - if so, how? |
| | How long is the processing time of electricity connection? Gas connection? How does this differ from other utilities? |
| | On average, how many new subdivisions do you develop in a year in Ontario? |
| | Do you have any concerns, in regard to collaborating with LDCs, as the volume of subdivisions increases to meet the Ministry's objective of 1.5 million new homes in Ontario? |
| | How has labor supply and costs changed? What impact has this had on development? |
| | Will labor availability be impacted as the housing demands increase in Ontario? |
| | How has material supply and costs changed? What impact has this had on development? |
| Understanding the Ideal Future State | What would be your ideal future state when working with Ontario LDCs to achieve the Ministry's development objectives? |
| | What do you feel needs to be changed in terms of policies or Ontario LDC practices to achieve this? |
| Additional Areas of Opportunity | Are there any other potential blockers to the goal of constructing 1.5 million new homes in Ontario by 2030? |
| | Is there any additional information you would like to share? |

| | |
|---|---|
| General: Process and Timelines | How many total new customer connections do you work on in one year? |
| | What percentage of new customer connections are represented by new residential subdivisions? |
| | On average, how long does it take you to develop a cost estimate for the subdivision new connection? |
| | What are the factors that impact these estimation timelines the most? |
| | During execution, how are variances between cost estimates and actuals handled, both in case the estimates are higher or lower than the actuals, for line expansion and the subdivision build? |
| | Please describe if and how historical actuals are used in forecasting future costs and creating estimates. |
| | What percentage of residential subdivision projects that go through initial estimation get executed? |
| | What percentage of projects are delivered on time? For the projects that are delayed or incur cost overruns, what are the most common reasons? |
| | What are the top risks impacting your ability to plan and deliver new connections to residential subdivisions and how do you mitigate them? |
| | How is data related to new connections currently tracked and reported on, both within your organization and with the OEB? |
| Material | Do you pre-order material to have it in stock or do you order once you know it will be used for a future development? |
| | Are there any constraints or delays accessing materials? If so, what are they? |
| | On average, how much have material prices increased? If prices have impacted your new connection process, how so? |
| | How are your estimation methodologies updated over a period, as the cost of estimation inputs of materials change over a period? |
| Labor (Line Expansion and Subdivision Development) | Is line expansion labour typically done in house (internal) or contracted out? |
| | Follow up: Are there any issues with availability of workforce in this scenario? How does it cause challenges for your timeline? If so, describe the constraints. |
| | Is subdivision labour typically done in house (internal) or contracted out? |
| | Follow up: Are there any issues with availability of workforce in this scenario? How does it cause challenges for your timeline? If so, describe the constraints. |
| | How are your estimation methodologies updated over a period, as the cost of estimation inputs of labour change over a period? |
| Design (line Expansion and Subdivision Development) | Is the line expansion design work typically done in house (internal) or contracted out? |
| | What is the average duration (weeks) of the line expansion design process? |
| | Follow-up: What factors/ constraints impact the timelines of the design process? |
| | Is the subdivision design work typically done in house (internal) or contracted out? |
| | What is the average duration (weeks) of the subdivision design process? |
| | Follow-up: What factors/ constraints impact the timelines of the overall design process? |
| Overhead | Do you apply overhead charges to new customer connections? If so, what is the percentage or formula used? |

| | |
|---|---|
| | Can you identify overhead costs that have been consistently challenging to manage or reduce? |
| Contingency | Do you bill your customers on estimates or actuals? |
| | Follow-up: If you initially bill on estimates, how do you true-up with customers? If you bill customers on actuals, please type N/A. |
| | If you do not apply contingency to customer contracts, are there any other measures you take to mitigate risk? |
| Areas of Improvement | Do you see any other opportunities or areas of improvement for enhanced efficiency in the estimation process, supply chain, and/ or construction process? If so, what are they? |
| | Is there any avenue to gather and incorporate feedback from developers? How is it managed, and can you share the top requests or recommendations you have received from developers around improving the overall new connections process? |
| | To support the government's vision of 1.5 million new homes in Ontario by the year 2030, where do you anticipate most of your challenges to arise? What measures would most help you in proactively addressing them? |

The surveys displayed above were sent to builders/developers and electricity distributors in Ontario to collect responses. Some electricity distributors and builders/developers were also engaged in additional interviews and discussions where additional questions were asked based on information that was being shared live. Please note, the regulator interview did not follow any particular guide as the purpose was to gather additional information on cost studies.

# Current gas rates for supply (effective October 1, 2024)

Each utility has different supply rates. Delivery rates also vary based on several factors, including their operating costs. This chart shows supply rates for each of the natural gas utilities whose rates we set.

- **Backgrounder - Enbridge (pdf)** (September 24, 2024)
- **Backgrounder - EPCOR (pdf)** (September 24, 2024)

| Utility Name | Gas Supply Charge | Detailed Rates |
|---|---|---|
| Enbridge Gas Inc. - Union South Rate Zone* | 12.3514 ¢/$m^3$ | **View detailed rates (pdf)** |
| Enbridge Gas Inc. - Union North East Rate Zone** | 13.6413 ¢/$m^3$ | **View detailed rates (pdf)** |
| Enbridge Gas Inc. - Union North West Rate Zone | 5.5482 ¢/$m^3$ | **View detailed rates (pdf)** |
| Enbridge Gas Inc. | 7.7012 ¢/$m^3$ | **View detailed rates (pdf)** |
| EPCOR Natural Gas Limited Partnership (Aylmer)*** | 14.6771 ¢/$m^3$ | **View detailed rates (pdf)** |

| Utility Name | Gas Supply Charge | Detailed Rates |
| --- | --- | --- |
| EPCOR Natural Gas Limited Partnership (South Bruce) | 12.1568 ¢/$m^3$ | **View detailed rates (pdf)** |

** The commodity rates for Union South include transportation charges.*
*** The commodity rates for Union North East include a portion of the transportation costs.*
**** The commodity rates for EPCOR (Aylmer) include storage and transportation charges.*
*To see how these natural gas rates relate to your overall bill, visit our **natural gas bill calculator**.*

**View past natural gas rates**

# How often does the Ontario Energy Board set new rates?

We set rates for the natural gas that you use (supply) 4 times a year.

Natural gas is a commodity that is traded on North American markets. Market prices rise and fall based on current supply and demand. Major weather events can also affect the market price.

We don’t allow Enbridge and EPCOR to earn a profit on the sale of gas. They must pass through to you the price they pay to buy natural gas on the open market, **with no markup.**

Every 3 months, natural gas utilities ask us to adjust their supply rates to cover:

# Heat Pump Calculator

This calculator is designed to help you understand how you could financially benefit from switching to a cold-weather air-source heat pump for heating and cooling your home and producing hot water. As well as saving money, there are important health benefits to be gained from eliminating gas from your home.

The calculator compares the cost of replacing conventional gas-fired equipment with slightly more efficient conventional units versus switching to proven heat-pump technology. To use the calculator, you need to know your current annual gas consumption (in cubic meters), which you can find by logging into your gas utility account (for Enbridge customers, see "view your gas use history" or "annual statement for taxes"). The assumptions built into the calculator are outlined below. The calculator will show you projected costs over 15 years, the minimum lifespan for most heating and cooling equipment. It provides an estimate only. To properly understand costs, you will need to get equipment quotes from a contractor.

### Incentives and financing

You can now receive zero interest financing from the Greener Homes Loan program. Ten-year loans for up to $40,000 are still available through this program.

If you live in the **City of Toronto**, you can access additional financing for a variety of measures through the Home Improvement Loan Program at a below-market rate (currently 4.09-4.69% depending on term).

Additional incentives and/or financing may also be available to residents of Ottawa, Kingston, and Durham.

More about heat pump technology.

Assumptions

## Heat Pump Savings Calculator

Gas usage per year (in cubic metres)

CALCULATE

| | |
|---|---|
| Current gas usage $m^3$ | 2200 |
| Space heating | 1870 |
| Water heating | 330 |

| Gas Furnace + Air Conditioner | |
|---|---|
| Gas furnace operating cost | $19,600 |
| Gas furnace capital cost (5% financing – 10 year term) | $5,500 |
| Gas water heater operating cost | $2,700 |
| Gas water heater capital cost (5% financing – 10 year term) | $2,500 |
| AC operating cost | $3,500 |
| AC capital cost (5% financing – 10 year term) | $5,500 |
| **Total cost** | **$39,300** |

| Heat Pump | |
|---|---|
| ASHP space heating operating cost | $13,200 |
| Heat Pump Water Heater operating cost | $1,500 |
| ASHP cooling operating cost | $2,900 |
| Heat Pump Water Heater capital cost (0% financing – 10 year term) | $5,000 |
| ASHP heating and cooling system capital cost (0% financing – 10 year term) | $16,500 |
| Electric Panel Upgrade | $2,000 |
| **Total cost** | **$41,100** |

ENBRIDGE GAS INC.

Answer to Environmental Defence Motion Question

Reference:

EB-2022-0200, Hearing Transcript, Volume Two, July 14, 2023, p. 22, ln. 14.

EB-2023-0201, Exhibit I.ED-23, Page 4, Table 2.

Question:

In relation to the Customer Count Variance Account described by the Current Energy Group, provide the average revenue per customer and the average incremental cost per customer for the general service customer classes, and if those figures differ significantly from $600 in average revenue and $74.89 in incremental costs for residential customers, to explain why.

Response[1]:

The $600 in average revenue is for all general service customers, not solely residential rate classes.

Enbridge Gas notes that the average distribution revenue, excluding DSM costs, for a residential customer is approximately $500. The incremental O&M for a Rate 1 customer based on the Phase 3 2024 Cost Allocation Study[2] and the O&M costs as approved in the Phase 1 Decision is $94.12. The incremental cost of $74.89 referenced in the question was the incremental O&M cost for a residential Rate 1 customer presented as part of the Eganville Leave to Construct Application[3]. The increase in cost is a result of the harmonized cost study and the length of time and change in costs since the last approved cost studies. Please see Table 1 for a summary of the average revenue and incremental O&M cost per customer by rate class for general service customers.

[1] Enbridge Gas wishes to indicate that this answer has been prepared as fully as possible in the time available. Enbridge Gas may have further information based on better understanding of the question being asked, and on having more time to consider and respond.
[2] This cost allocation study will be filed in Phase 3 and maintains current rate zones.
[3] EB-2023-0201, Exhibit I.ED-23, p. 4, Table 2. This cost was based on the 2018 cost study escalated by PCI annually.

Table 1
Average Revenue per Customer and Incremental O&M per Customer

| Line No. | | Number of Customers | Average Revenue/ Customer ($) | Incremental O&M per Customer ($) |
|---|---|---|---|---|
| | | (a) | (b) | (c) |
| 1 | Rate 1 | 2,163,088 | 485 | 94.12 |
| 2 | Rate 6 | 172,974 | 2,167 | 228.92 |
| 3 | Rate 01 | 369,871 | 616 | 118.80 |
| 4 | Rate 10 | 2,205 | 11,641 | 1,235.38 |
| 5 | Rate M1 | 1,205,199 | 493 | 95.36 |
| 6 | Rate M2 | 8,077 | 10,182 | 928.47 |
| 7 | Total General Service | 3,921,414 | 600 | |
| 8 | Total Residential | 3,738,158 | 500 | |

The incremental costs Enbridge Gas incurs for adding a customer includes the O&M cost as shown in the table above, as well as the capital cost. The average incremental cost of adding a residential customer, determined by the revenue requirement calculation that includes both the incremental O&M and capital cost is between $491 and $610 in Enbridge Gas's rate zones. Please see line number 16, column (e) in Tables 2 to 4 which show the average revenue requirement of attaching a feasible customer. Note, the costs underpinning Tables 2 to 4 are based on the best available information today, which is the Phase 3 2024 Cost Allocation Study for current rate zones.[4] The Phase 3 2024 Cost Allocation Study is used as it is the only cost study that has been updated for the revenue requirement approved in Phase 1. The assumptions Enbridge Gas made in order to develop the cost estimates include:

a) The distribution rates used in determining the customer addition capital expenditure are based on the Phase 3 2024 Cost Allocation Study (consistent with Table 1).

b) The capital expenditure per customer attachment is calculated to be equal to Enbridge Gas earning a PI of 1.0 over 40 years (line 1 of Tables 2 to 4). This is a notional number and does not consider the actual cost to add a specific customer

[4] The Phase 3 2024 Cost Allocation Study includes the revenue requirement approved as part of the Phase 1 Interim Decision and Rate Order (EB-2022-0200), but does not include costs from the Phase 2 Settlement Proposal.

which could be higher or lower. Enbridge Gas believes this approach of estimating the incremental capital cost of adding a customer is appropriate as Enbridge Gas's portfolio must be equal to or greater than a PI of 1.0.

c) The revenue assumptions exclude projects with a SES and TCS surcharge.

d) The O&M amounts included reflect average variable O&M costs of each rate class, and do not include fixed O&M costs which can increase or decrease in a stepped fashion with material changes in the number of customers served, or due to other drivers. Please see Table 1 for the incremental O&M per customer (also see line 3 of Tables 2 to 4).

Table 2

Estimate of Incremental Revenue Requirement of Attaching Feasible Rate 1 Customers

| Line No. | Particulars ($) | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| | Rate Base Investment | | | | | |
| 1 | Capital Expenditures | 4,548 | 4,548 | 4,548 | 4,548 | 4,548 |
| 2 | Average Investment | 4,304 | 8,667 | 12,899 | 17,001 | 20,972 |
| | Revenue Requirement Calculation: | | | | | |
| | Operating Expenses: | | | | | |
| 3 | Operating and Maintenance Expenses | 94 | 188 | 282 | 376 | 471 |
| 4 | Depreciation Expense | 120 | 250 | 381 | 511 | 642 |
| 5 | Property Taxes | 14 | 27 | 41 | 55 | 68 |
| 6 | Total Operating Expenses | 227 | 466 | 704 | 942 | 1,181 |
| | Required Return (1) | | | | | |
| 7 | Interest Expense | 132 | 265 | 395 | 521 | 642 |
| 8 | Return on Equity | 151 | 303 | 451 | 595 | 734 |
| 9 | Required Return | 282 | 569 | 847 | 1,116 | 1,376 |
| 10 | Total Operating Expense and Return | 510 | 1,034 | 1,550 | 2,058 | 2,557 |
| | Income Taxes | | | | | |
| 11 | Income Taxes - Equity Return (2) | 54 | 109 | 163 | 215 | 265 |
| 12 | Income Taxes - Utility Timing Differences(3) | (55) | (101) | (141) | (175) | (156) |
| 13 | Total Income Taxes | (1) | 9 | 22 | 39 | 109 |
| 14 | Total Revenue Requirement | 509 | 1,043 | 1,573 | 2,097 | 2,666 |
| 15 | Number of Customers | 1 | 2 | 3 | 4 | 5 |
| 16 | Average Revenue Requirement per Customer | 509 | 522 | 524 | 524 | 533 |

Notes:

(1) The required return assumes a capital structure of 62% debt at 4.94% and 38% common equity at the 2024 Board Formula return of 9.21%. The annual required return is as follows: Average Investment (row 2) * 62% * 4.94% plus Average Investment (row 2) * 38% * 9.21%

(2) Taxes related to the equity component of the return at a tax rate of 26.5%.

(3) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Table 3

Estimate of Incremental Revenue Requirement of Attaching Feasible Rate 01 Customers

| Line No. | Particulars ($) | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| | Rate Base Investment | | | | | |
| 1 | Capital Expenditures | 4,912 | 4,912 | 4,912 | 4,912 | 4,912 |
| 2 | Average Investment | 4,642 | 9,353 | 13,923 | 18,352 | 22,640 |
| | Revenue Requirement Calculation: | | | | | |
| | Operating Expenses: | | | | | |
| 3 | Operating and Maintenance Expenses | 119 | 238 | 356 | 475 | 594 |
| 4 | Depreciation Expense | 129 | 270 | 411 | 552 | 693 |
| 5 | Property Taxes | 32 | 64 | 96 | 128 | 160 |
| 6 | Total Operating Expenses | 280 | 572 | 863 | 1,155 | 1,447 |
| | Required Return (1) | | | | | |
| 7 | Interest Expense | 142 | 286 | 426 | 562 | 693 |
| 8 | Return on Equity | 162 | 327 | 487 | 642 | 792 |
| 9 | Required Return | 305 | 614 | 914 | 1,204 | 1,486 |
| 10 | Total Operating Expense and Return | 585 | 1,185 | 1,777 | 2,359 | 2,933 |
| | Income Taxes | | | | | |
| 11 | Income Taxes - Equity Return (2) | 59 | 118 | 176 | 232 | 286 |
| 12 | Income Taxes - Utility Timing Differences(3) | (60) | (109) | (152) | (189) | (168) |
| 13 | Total Income Taxes | (1) | 9 | 24 | 42 | 117 |
| 14 | Total Revenue Requirement | 584 | 1,195 | 1,801 | 2,402 | 3,050 |
| 15 | Number of Customers | 1 | 2 | 3 | 4 | 5 |
| 16 | Average Revenue Requirement per Customer | 584 | 597 | 600 | 600 | 610 |

Notes:

(1) The required return assumes a capital structure of 62% debt at 4.94% and 38% common equity at the 2024 Board Formula return of 9.21%. The annual required return is as follows:

Average Investment (row 2) * 62% * 4.94% plus Average Investment (row 2) * 38% * 9.21%

(2) Taxes related to the equity component of the return at a tax rate of 26.5%.

(3) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Table 4

Estimate of Incremental Revenue Requirement of Attaching Feasible Rate M1 Customers

| Line No. | Particulars ($) | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| | Rate Base Investment | | | | | |
| 1 | Capital Expenditures | 3,955 | 3,955 | 3,955 | 3,955 | 3,955 |
| 2 | Average Investment | 3,738 | 7,531 | 11,210 | 14,777 | 18,229 |
| | Revenue Requirement Calculation: | | | | | |
| | Operating Expenses: | | | | | |
| 3 | Operating and Maintenance Expenses | 95 | 191 | 286 | 381 | 477 |
| 4 | Depreciation Expense | 104 | 218 | 331 | 445 | 558 |
| 5 | Property Taxes | 26 | 51 | 77 | 103 | 129 |
| 6 | Total Operating Expenses | 225 | 460 | 694 | 929 | 1,163 |
| | Required Return (1) | | | | | |
| 7 | Interest Expense | 114 | 231 | 343 | 453 | 558 |
| 8 | Return on Equity | 131 | 264 | 392 | 517 | 638 |
| 9 | Required Return | 245 | 494 | 736 | 970 | 1,196 |
| 10 | Total Operating Expense and Return | 470 | 954 | 1,430 | 1,899 | 2,360 |
| | Income Taxes | | | | | |
| 11 | Income Taxes - Equity Return (2) | 47 | 95 | 141 | 186 | 230 |
| 12 | Income Taxes - Utility Timing Differences(3) | (48) | (88) | (122) | (152) | (135) |
| 13 | Total Income Taxes | (1) | 7 | 19 | 34 | 95 |
| 14 | Total Revenue Requirement | 470 | 961 | 1,449 | 1,933 | 2,454 |
| 15 | Number of Customers | 1 | 2 | 3 | 4 | 5 |
| 16 | Average Revenue Requirement per Customer | 470 | 481 | 483 | 483 | 491 |

Notes:

(1) The required return assumes a capital structure of 62% debt at 4.94% and 38% common equity at the 2024 Board Formula return of 9.21%. The annual required return is as follows:

Average Investment (row 2) * 62% * 4.94% plus Average Investment (row 2) * 38% * 9.21%

(2) Taxes related to the equity component of the return at a tax rate of 26.5%.

(3) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Updated Response: /u

By letter dated December 4, 2024, ED requested Enbridge Gas to update its response to motion question #3 to indicate “the cost of an additional customer incremental to the costs already covered by base rates.” The Company confirms that it believes its original response remains appropriate. The Company agrees that base rates can support a certain level of capital spending, in total. However, base rates and the annual escalation of those rates under a price cap rate setting mechanism during an incentive regulation (“IR”) term are not allocated to a specific type of capital expenditure recovered within rates. Generally, revenue growth through price cap escalation alone is insufficient to fully fund the cost associated with capital required to add customers and maintain safe and reliable service during the IR term. Growth and efficiencies are required to make up the difference and to earn allowed ROE under incentive regulation. What is clear is that there are incremental capital and operating costs associated with adding customers, that would not otherwise be incurred in the absence of doing so.

As part of the regulatory compact, the Company is obligated to serve new customers in return for the revenues generated from them. The obligation to serve is not compatible with the decoupling mechanisms proposed by ED, which are contrary to the OEB’s established rate setting mechanisms. The incremental revenues from customer growth are required to fund the necessary capital investments which enable the Company to add customers.

Further, when viewed in isolation, the cost of adding a customer typically outweighs the incremental revenues received from that customer in the first number of years. This is because the carrying costs of the associated capital costs are highest in the early years, but slowly decrease over time as the cost of assets are recovered through depreciation, whereas rates/revenues reflect an average carrying cost of assets (due to the varied mix of assets at all ages reflected in rate base). As a result, in the near term, where rates are set through a price cap mechanism, not cost of service, the addition of customers actually creates a drag on earnings, not a windfall.

Table 5 illustrates the forecast impact of customer additions over the IRM term. The forecast costs are shown at line 15 and reflect the cumulative revenue requirement of customer connection capital plus incremental operating costs per customer addition. Customer addition revenues, which are shown on line 18, reflect the revenue requirement associated with 2024 customer connection capital which is embedded in base rates and subject to annual PCI escalation, plus the cumulative gross margin associated with customer additions. Finally, line 19 provides the variance between customer addition costs and revenues, which shows the costs of customer connections outweigh the associated revenues. Of course, this issue would be amplified if the Company were not permitted to retain incremental revenues from new customer additions during the IRM term.

Table 5
Revenue Shortfall in IRM Term for Illustration

| Line No. | Particulars | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| 1 | PCI (%) | | 3.3% | 1.7% | 1.7% | 1.7% |
| 2 | Customer Adds ($) (1) | | 40,533 | 38,879 | 37,000 | 35,200 |
| 3 | Revenue/ Customer($) (2) | 600 | 620 | 631 | 641 | 652 |
| 4 | O&M/ customer ($) (3) | 94 | 97 | 99 | 100 | 102 |
| 5 | Property Tax /Customer ($) (3) | 14 | 14 | 15 | 15 | 15 |
| 6 | Capital Expenditures ($Millions) (4) | 224 | 286 | 256 | 230 | 208 |
| | Revenue Requirement ($Millions) | | | | | |
| 7 | RR- 2024 Customer Adds | (5) | 21 | 21 | 21 | 20 |
| 8 | RR- 2025 Customer Adds | - | (5) | 27 | 26 | 26 |
| 9 | RR- 2026 Customer Adds | - | - | (2) | 24 | 23 |
| 10 | RR- 2027 Customer Adds | - | - | - | (1) | 21 |
| 11 | RR- 2028 Customer Adds | - | - | - | - | 3 |
| 12 | Total RR Capital Related (sum of lines 7 to 11) | (5) | 17 | 45 | 70 | 94 |
| 13 | O&M (line 2 x line 4) | | 4 | 8 | 11 | 15 |
| 14 | Property Tax (line 2 x line 5) | | 1 | 1 | 2 | 2 |
| 15 | Total Cost (sum of lines 12 to 14) | | 21 | 54 | 83 | 111 |
| 16 | Base Revenue Escalated @ PCI | (5) | (5) | (5) | (5) | (6) |
| 17 | Customer Growth-Revenue (line 2 x line 3) | | 25 | 50 | 73 | 96 |
| 18 | Total Revenue- Customer Adds | | 20 | 44 | 68 | 91 |
| 19 | Revenue Shortfall (line 15 - line 18) | | 1 | 10 | 15 | 20 |

Notes:

(1) Customer additions based on AMP filed Nov 8, 2024.
(2) $600 per customer is the average for all general service customers, provided in Table 1, escalated for PCI in line 1.
(3) O&M and property tax based on Table 2, line 3, column (a).
(4) 2024 Customer Growth based on Phase 1 Rate order, and 2025-2028 based on AMP filed November 8, 2024.

The Company also notes that rate base growth and the associated carrying costs (i.e. cost of capital and depreciation expense and taxes), which has resulted from the level of capital expenditures required to maintain the safe operation of the system (i.e. through replacement of long lived assets, being replaced in current dollars) and meet growth requirements, has exceeded the revenue growth that is attributable to solely PCI escalation of base rates. Revenue growth due solely to PCI escalation is not sufficient to support the costs associated with capital requirements.

Revenues associated with PCI, growth, and cost efficiencies have been leveraged under the Price Cap rate setting mechanism to accommodate capital requirements. As rates are not tied to costs under a price cap mechanism, the ability to offset cost pressures in one area through efficiencies or revenue growth (i.e. scale economies) is a key attribute to the mechanism. The revenues achieved through the Price Cap mechanism should be treated as a whole (not segregated). This allows a utility to allocate funds across a variety of cost categories including O&M, capital and cost of capital. Isolating revenues by specific cost categories, such as growth capital contradicts the principles of Performance Based Regulation (PBR) and restricts the utility's operational flexibility.

The expectation that incremental revenues from the growth capital enables the funding of additional capital is reflected by the inclusion of the growth (g) factor in the ICM formula. The purpose of the g-factor is to account for the incremental capital funding that is notionally expected to be funded through existing rates resulting from revenues achieved from growth. By incorporating the g-factor, the ICM formula ensures that the incremental revenues generated from customer growth are recognized before incremental capital funding is awarded.

Finally, the imposition of either of the proposed decoupling mechanisms would impede the Company's ability to earn its allowed rate of return and a fair return, in any circumstance where more revenues are being returned to customers as compared to the cost offsets recognized. This impact is additive over an incentive regulation term.

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