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.

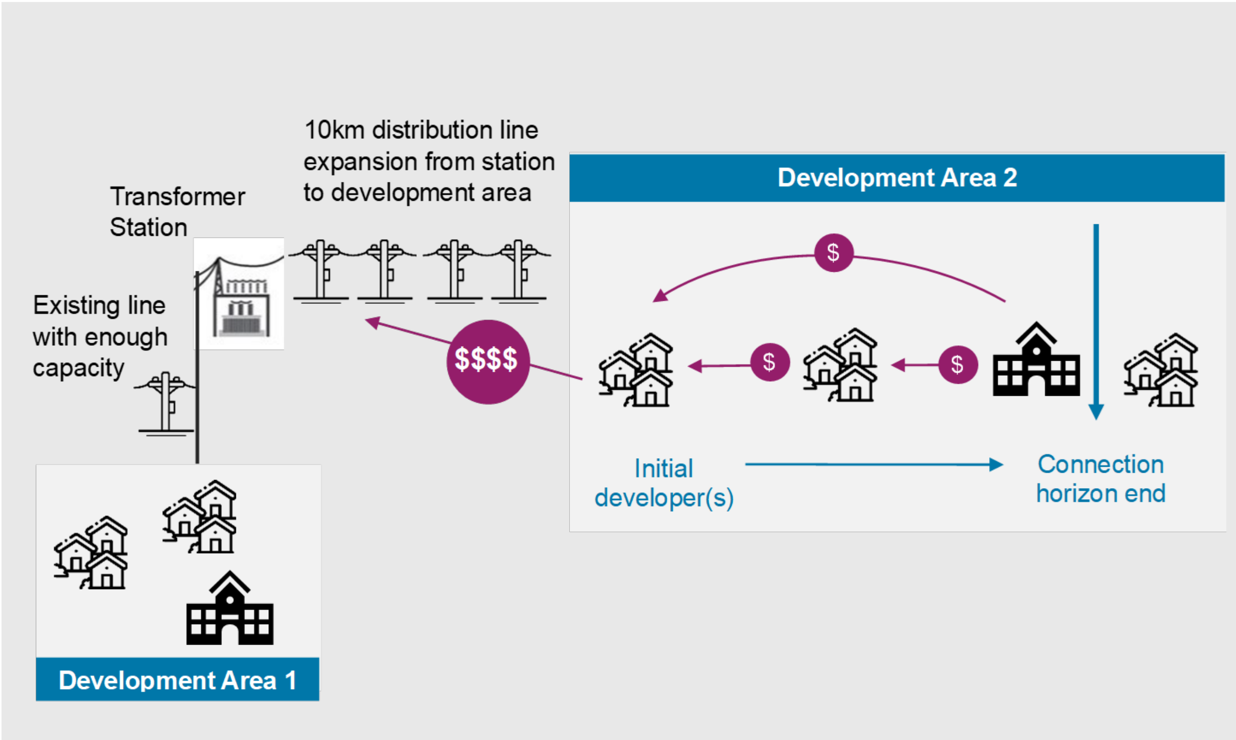
Part II presents findings from an OEB-commissioned study, performed by PricewaterhouseCoopers (PwC), that reviewed distribution system unit costs for connecting new subdivision developments based on a survey of six electricity distributors and identifies areas of potential improvement. Informed by the 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.

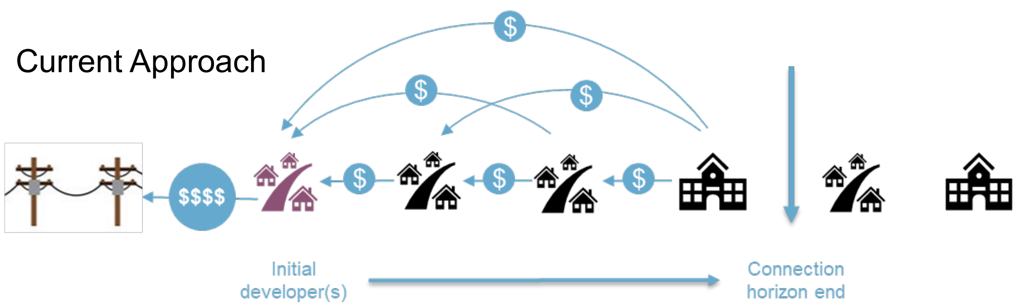
PATH FORWARD

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:

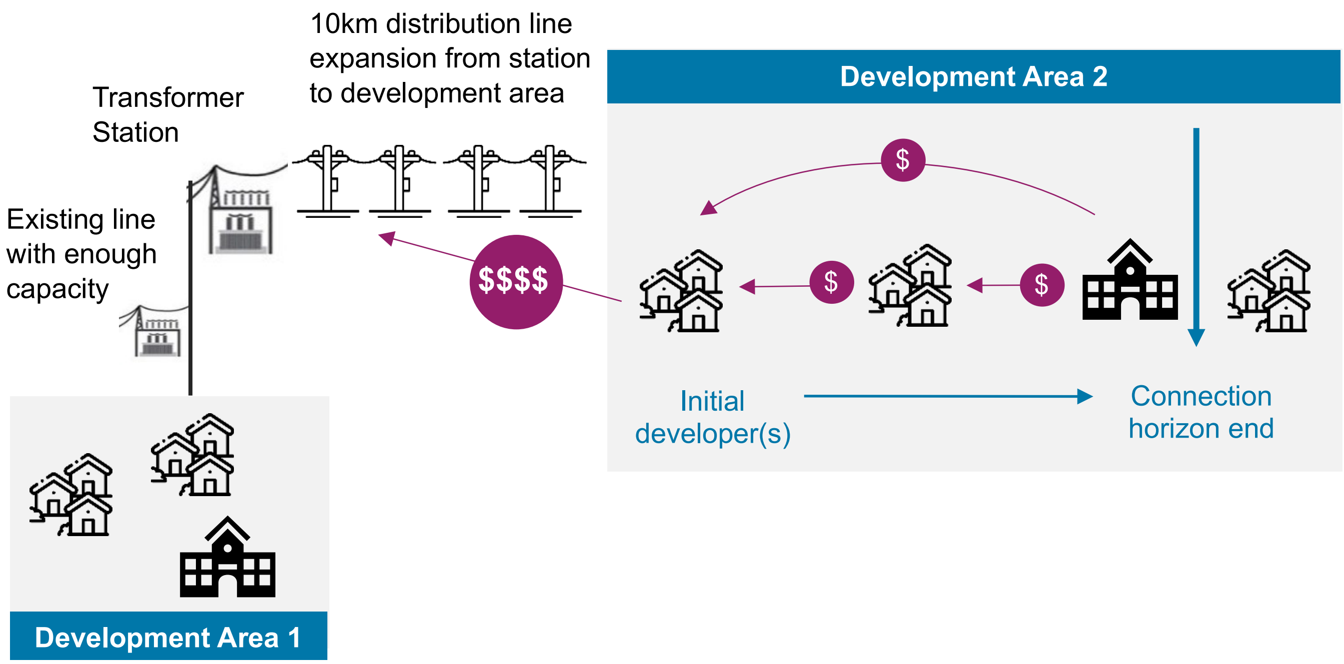
- Current Cost Recovery Framework & Greenfield Developments
- Growth and Ratepayer Costs
- Clarity regarding Current Rules
- Alignment of Planning

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

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[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.

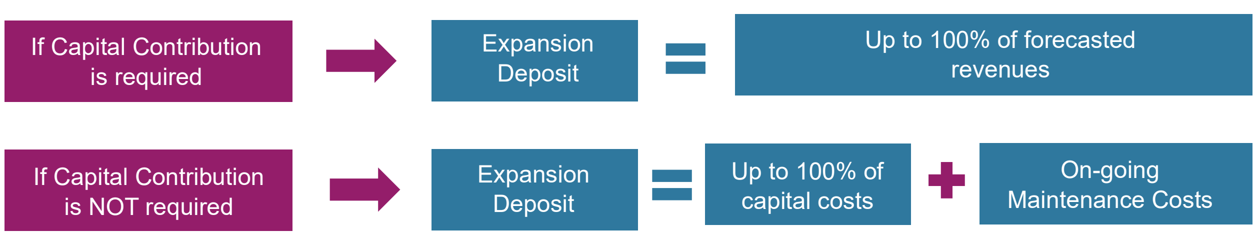
  Example 3.1.1: A developer initially plans for a subdivision of 400 homes to be connected, and an economic evaluation projects a shortfall of $100,000 between the costs and revenues from these homes. The developer pays a $100,000 capital contribution and provides a $300,000 expansion deposit to the distributor. 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

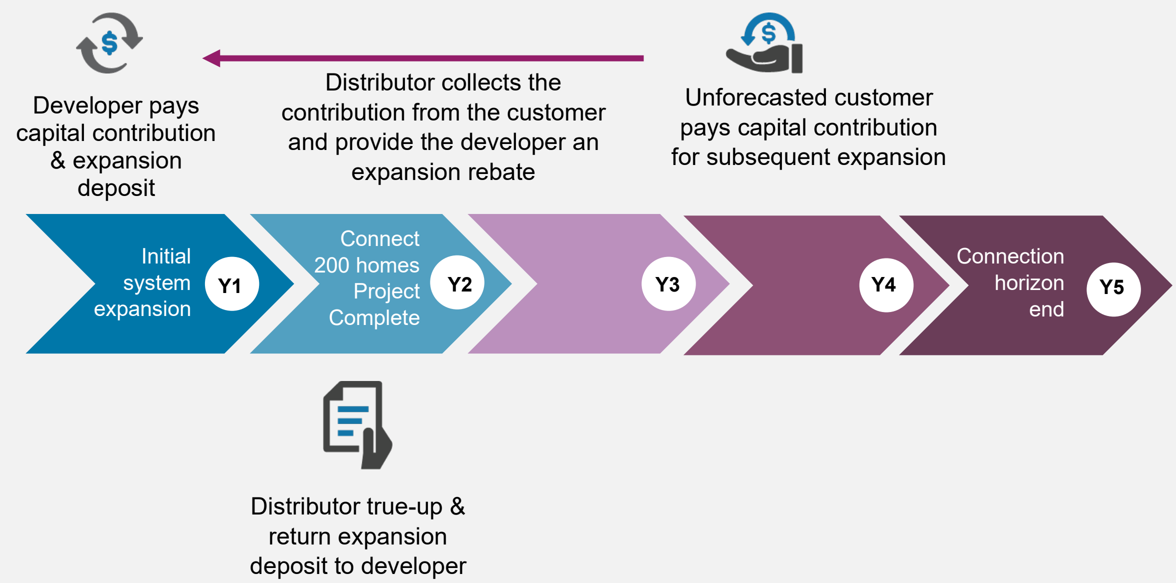
The revenue horizon is an input for revenue forecasting in an economic evaluation. A longer revenue horizon can lead to higher forecasted revenues, thereby reducing the shortfall between projected costs and revenues. Distributors have the discretion to set different revenue horizons for different customer 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.

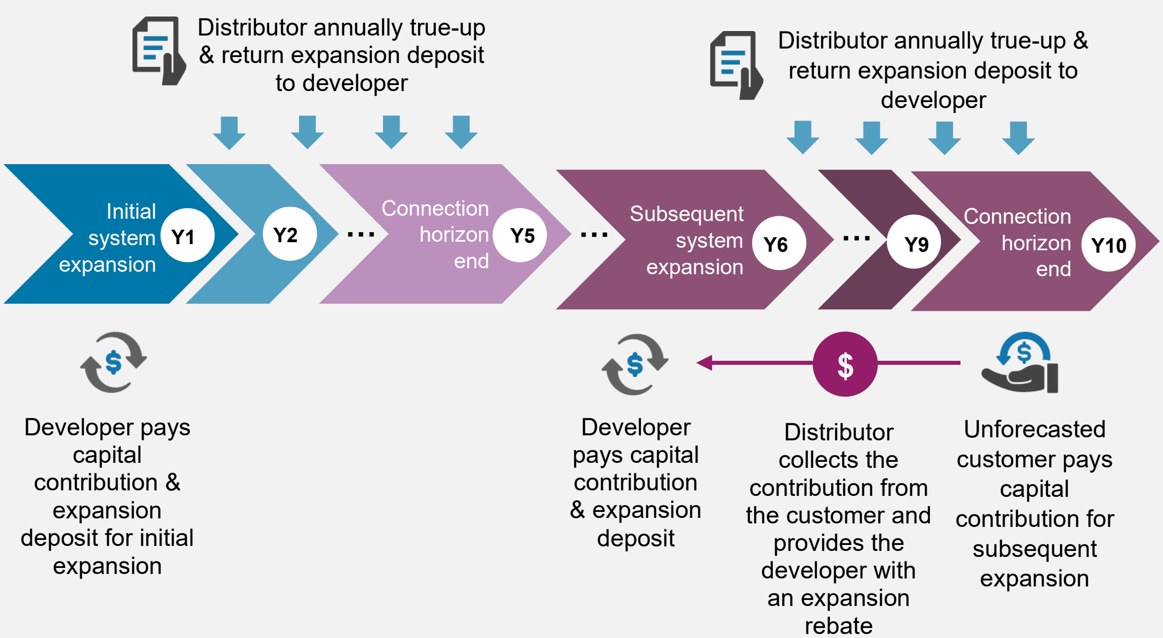
The economic evaluation for this project will include all capital costs, ongoing maintenance costs of the expansion, and forecasted revenues from these homes. Annually, the distributor will perform true-up calculations to reflect the actual number of homes connected and will adjust the expansion deposit 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**.

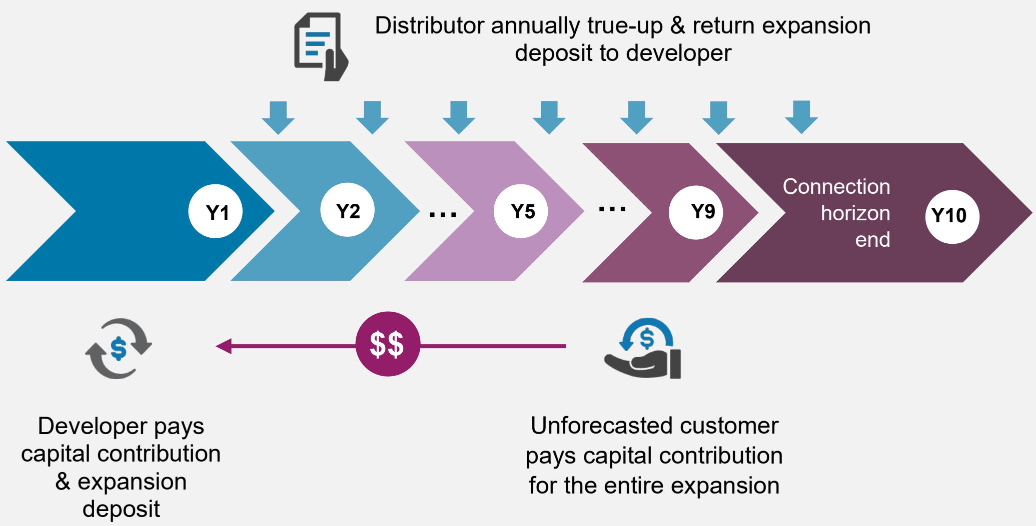
Example 3.2.2 Scenario 1: A developer plans to build 2,000 homes over 10 years, and the distributor opts to segment the project into two separate phases — connecting 1,000 homes in the first five years and another 1,000 homes in the subsequent five years — conducting separate economic evaluations for 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:

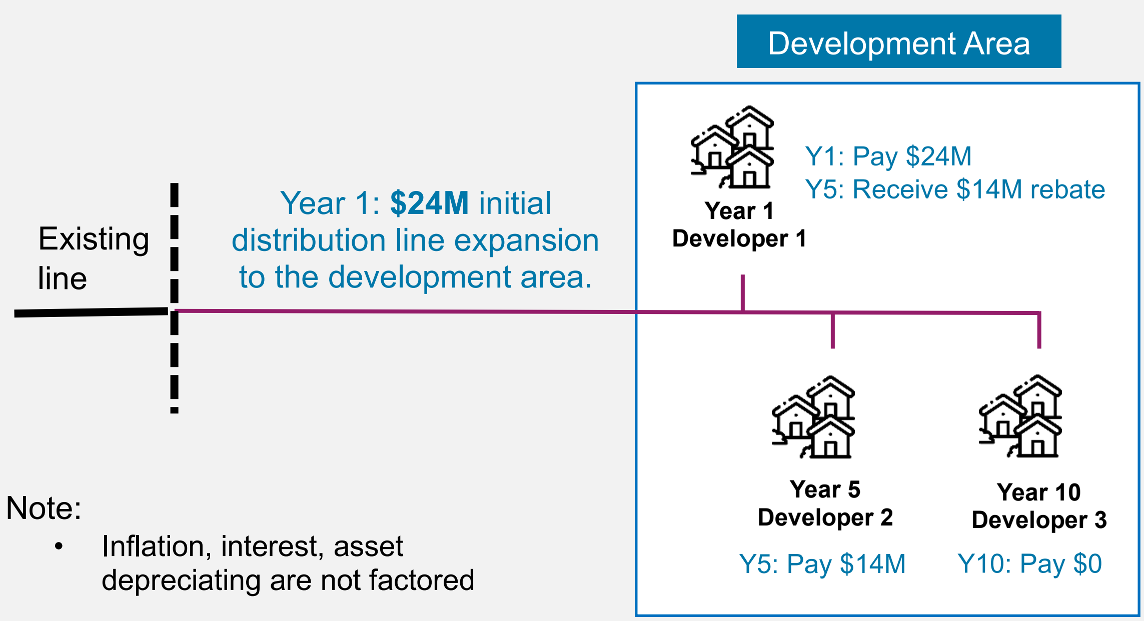
- When the connection horizon is extended, there is a higher likelihood that unforecasted customers will connect and contribute to the expansion. This provides the initial contributors a higher likelihood of receiving expansion rebates and thus reducing their costs to connect.
- Due to less precise estimation 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.

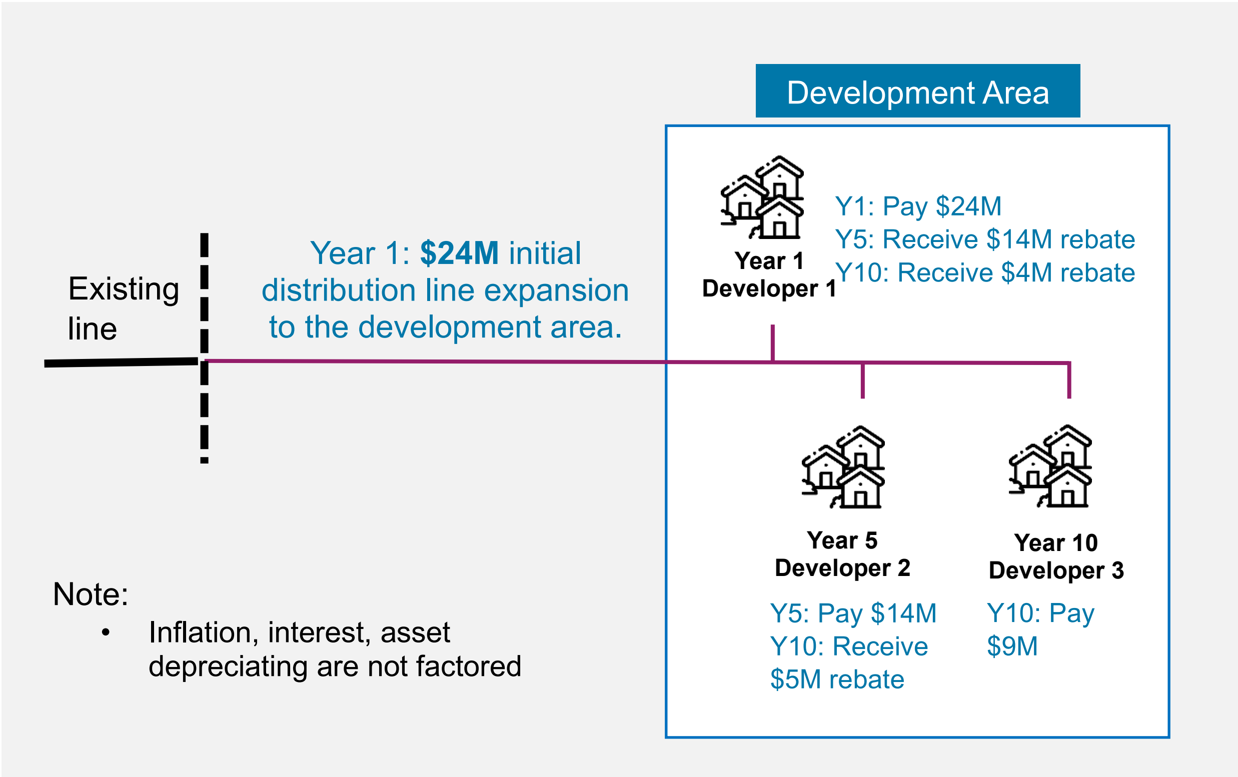
The following example demonstrates the potential impacts of the connection horizon on multi-phase subdivisions constructed by different developers.

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

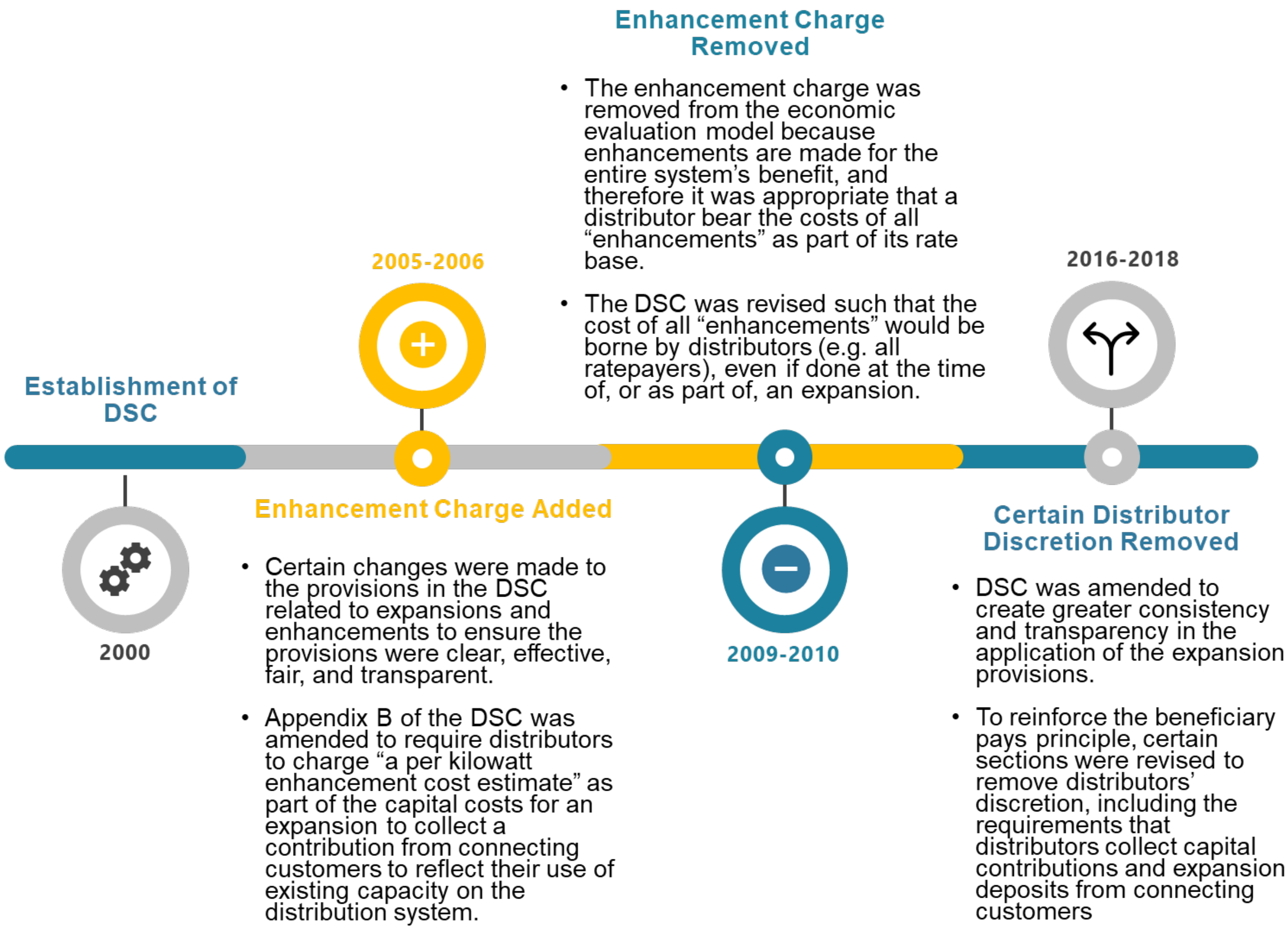
The DSC requires distributors to plan and develop the distribution system in anticipation of future load growth. This includes undertaking enhancements designed to improve the system's operational characteristics or alleviate capacity constraints. When considering these enhancements, distributors are 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.

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[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.

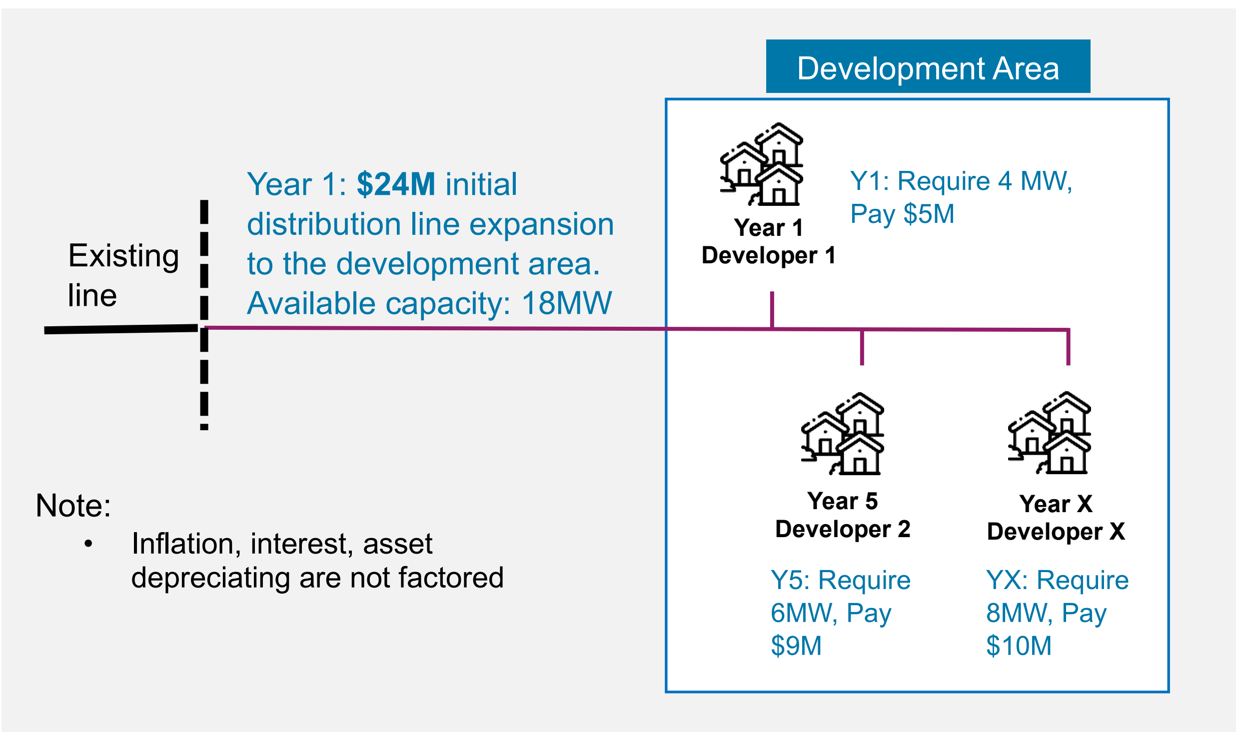
In response to concerns about the impact of upfront financing requirements, the proposed amendments will establish the distributor's ability to recover a capital contribution over time, rather than upfront. This approach will provide more financial flexibility to the developers and align the contributions 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

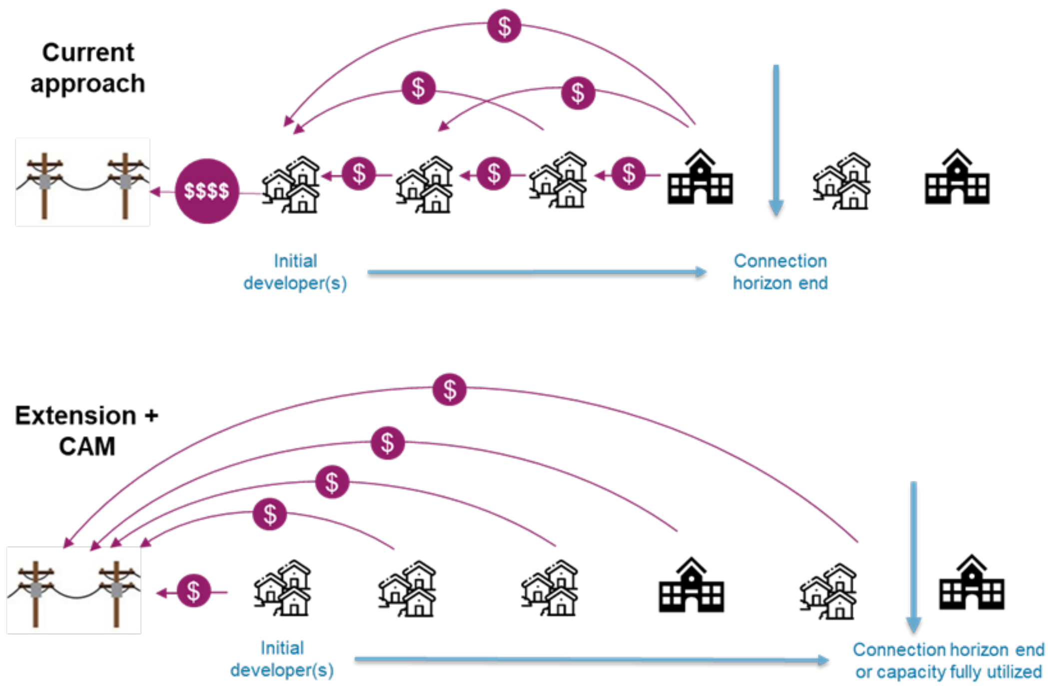
The OEB has reviewed its current cost recovery framework and assessed the feedback and insights gathered from stakeholders regarding the distribution system expansion for housing developments. This detailed consultation has illuminated specific challenges linked to large greenfield developments, notably 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

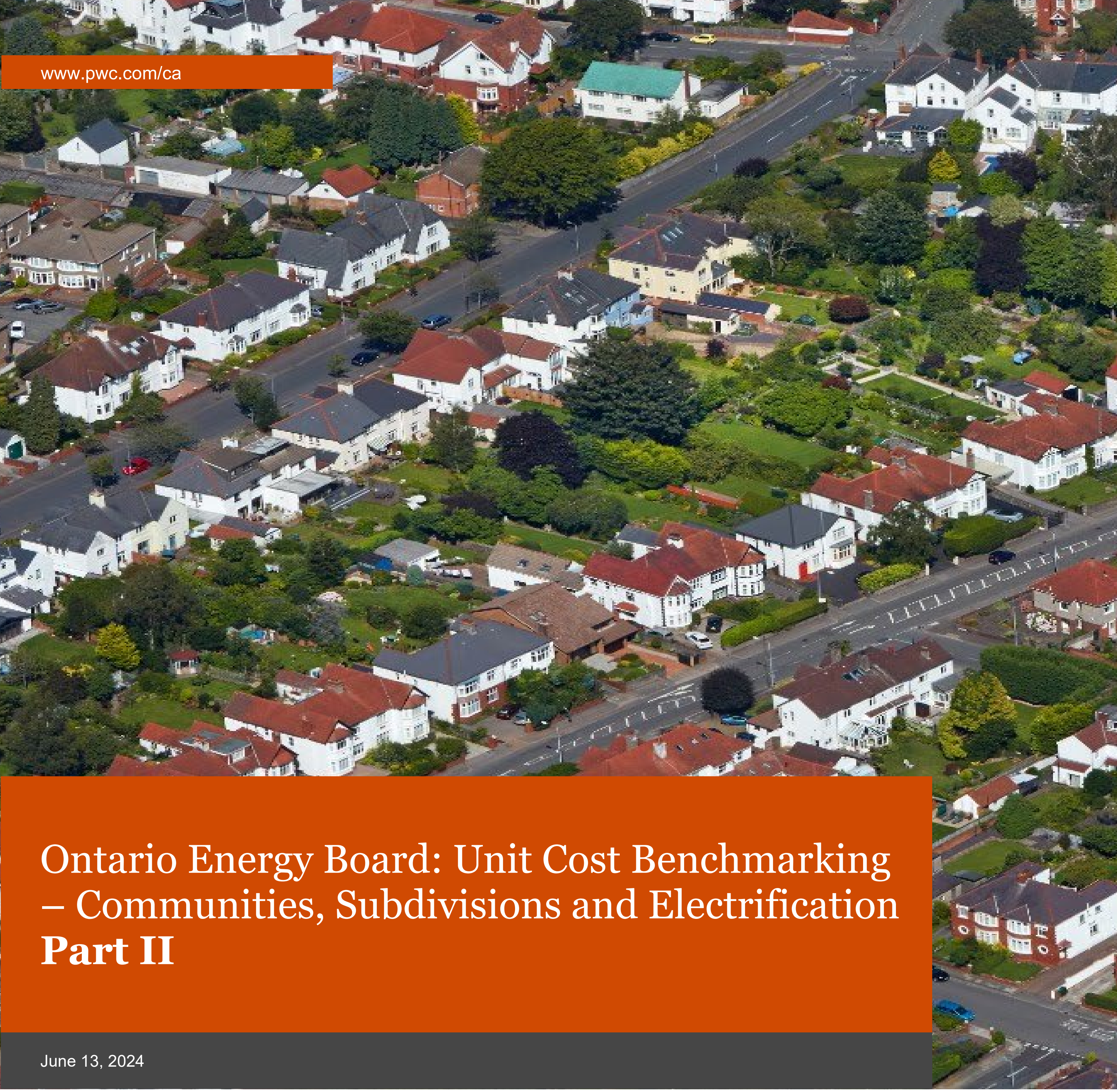
Organization Name	Consultation Role
Alectra Utilities Corporation	Meeting & written comments
Association of Municipalities of Ontario	Stakeholder Meeting
Building Industry and Land Development (BILD)	Meeting & written comments
Bluewater Power Distribution Corporation	Stakeholder Meeting
Brookfield Property	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



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Ontario Energy Board: Unit Cost Benchmarking – Communities, Subdivisions and Electrification **Part II**

June 13, 2024

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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.

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[2] Ontario Energy Board. *Distribution System Code*.

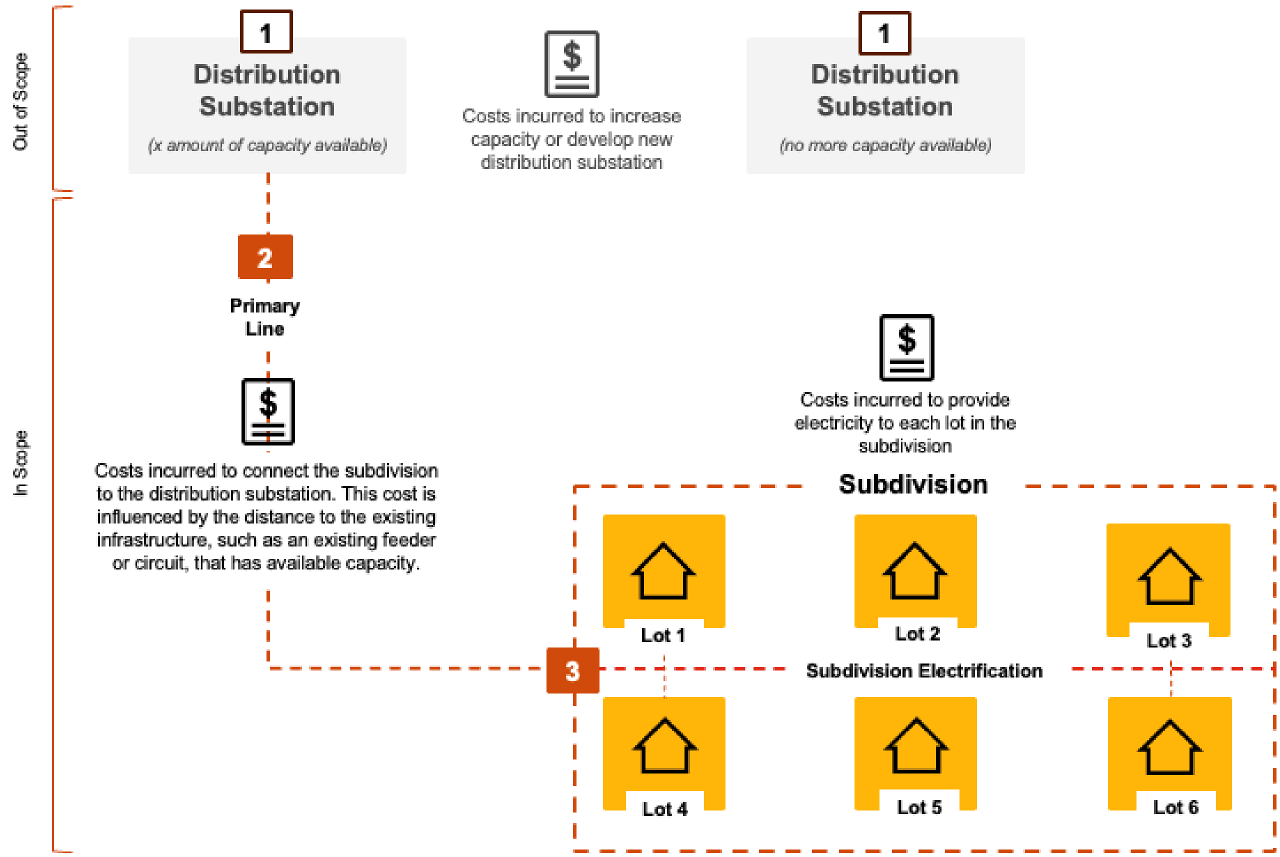

Figure 1 - Distribution System Overview

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.

	Greenfield			Brownfield *Density Increase*
Scenario Category	1. New Community Development / Detached Homes	2. House Development Project	3. Townhouse Development (Massive)	4. Established Residential Neighbourhood
Housing type	Single Family Home	Semi-detached, townhouse	Townhouses	Semi-detached, townhouse
# of lots and house size	50 and 200 lots 2500 sq. ft house size	200 lots 1800 sq. ft house size	500 and 1000 lots 1300 sq. ft house size	40 lots 1500 sq. ft house size
Network type	Overhead/Underground (Primary) & Underground (Subdivision)	Overhead (Primary) Overhead & Underground (Subdivision)	Overhead/Underground (Primary) & Underground (Subdivision)	Underground (Subdivision)
Dist. to nearest take-off point	5 km and 1 km	10 km and 5 km	10 km and 5 km	0
Load Type / Usage and Heat Source	• 200 A Load Usage • All Electric plus 2 EVs and Electric/Gas Hook-Up • Primary expansion / brand new circuit	• 200 A Load Usage • All Electric plus 2 EVs and Electric/Gas Hook-Up • Primary expansion / brand new circuit	• 100 A Load Usage • All Electric plus 2 EVs and Electric/Gas Hook-Up • Primary expansion / brand new circuit	• 100 A Load Usage • Electric and Gas Hook-Up • No expansion; some upgrades to existing network

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 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 Infill 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) 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.

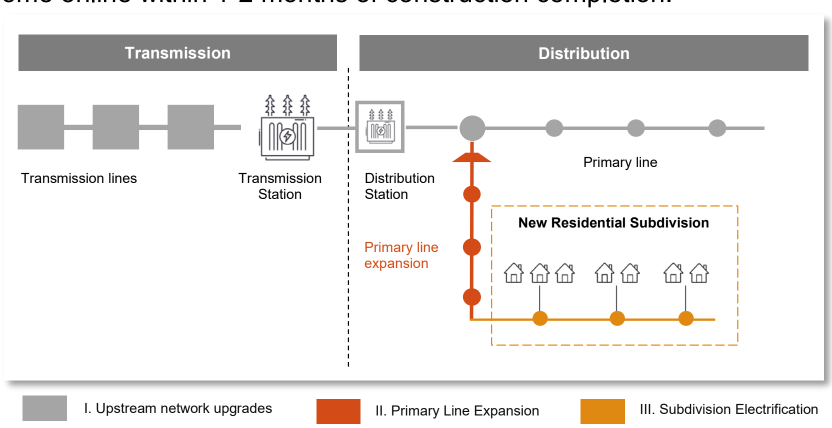

Figure 4 - Key electricity costs categories for new subdivision build

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.

<table>
<tr><th colspan="2">Primary Line Expansion</th><th colspan="2">Subdivision Electrification</th></tr>
<tr><th>Overhead Average Cost</th><th>Underground Average Cost</th><th>Gas Heated Average Cost</th><th>All Electric Average Cost</th></tr>
<tr><td>$551K / km</td><td>$1,518K / km</td><td>$7.5K / lot</td><td>$12.2K / lot</td></tr>
<tr><td>Min: $319 / km
Max: $1,060 / km</td><td>Min: $767 / km
Max: $2,695 / km</td><td>Min: $3.3 / lot
Max: $11.3 / lot</td><td>Min: $11.9 / lot
Max: $12.4 / lot</td></tr>
<tr><th colspan="2">Drivers of Variance</th><th colspan="2">Drivers of Variance</th></tr>
<tr><td colspan="2">
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.
</td><td colspan="2">
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.
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These variances and the drivers of the variances are explored in more depth in the following sections.

3.2.2 Electrical Infrastructure Cost Unitization

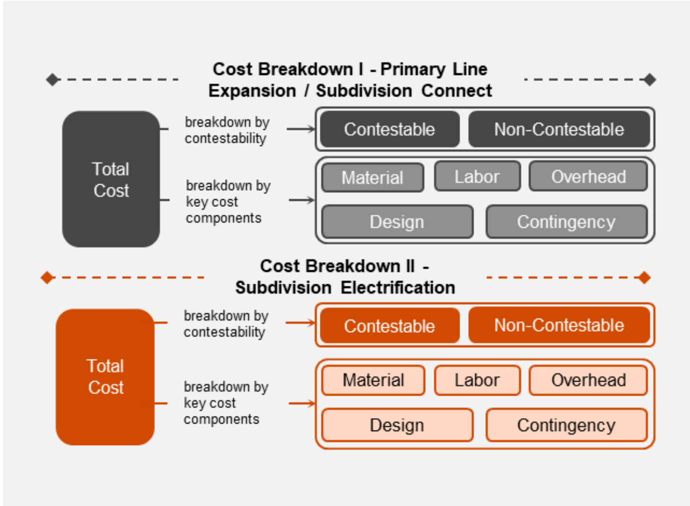


Figure 5 - Total Cost Analysis Framework

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).

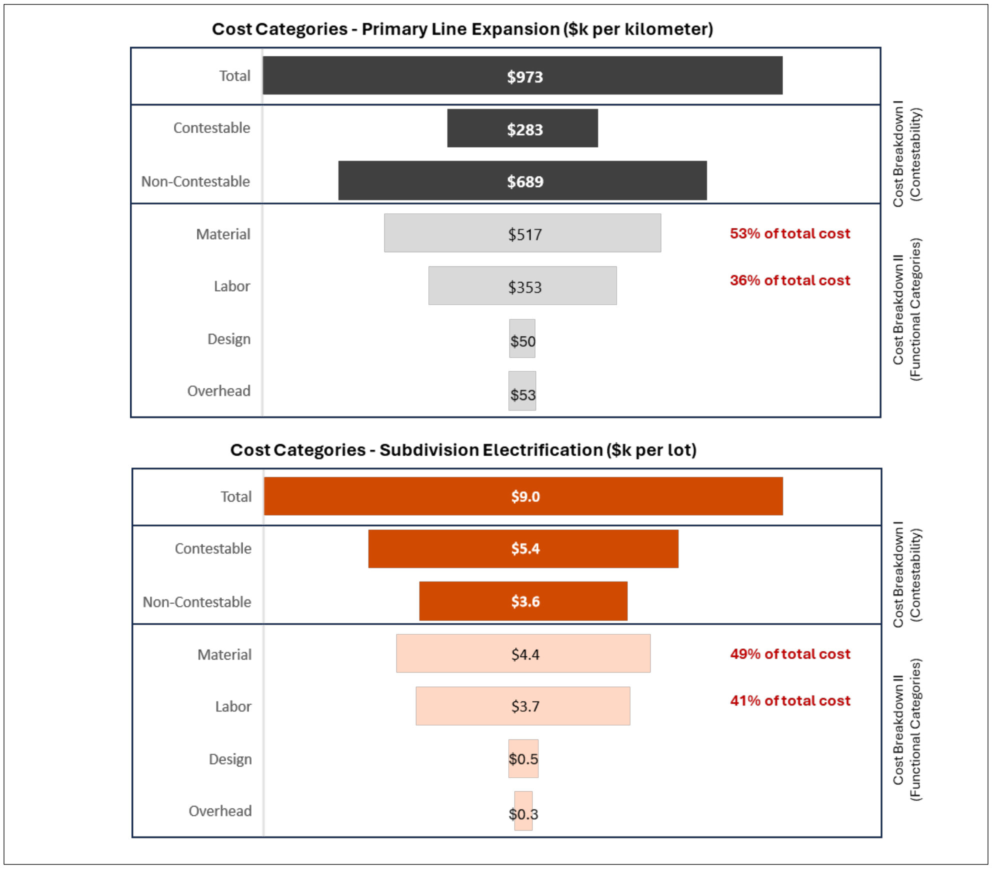


Figure 6 - Cost breakdown for primary line expansion ($k per kilometre) and subdivision electrification ($k per lot)

3.2.3 Sensitivity Analysis

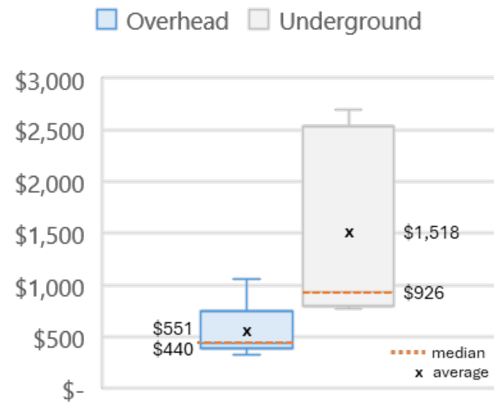
A review of the cost data highlighted two overarching design decisions in the construction of the primary line expansion and the subsequent electrification of the subdivision, which had the largest impact on overall cost variance (due to material selection, labor availability, and construction methodologies):

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%).

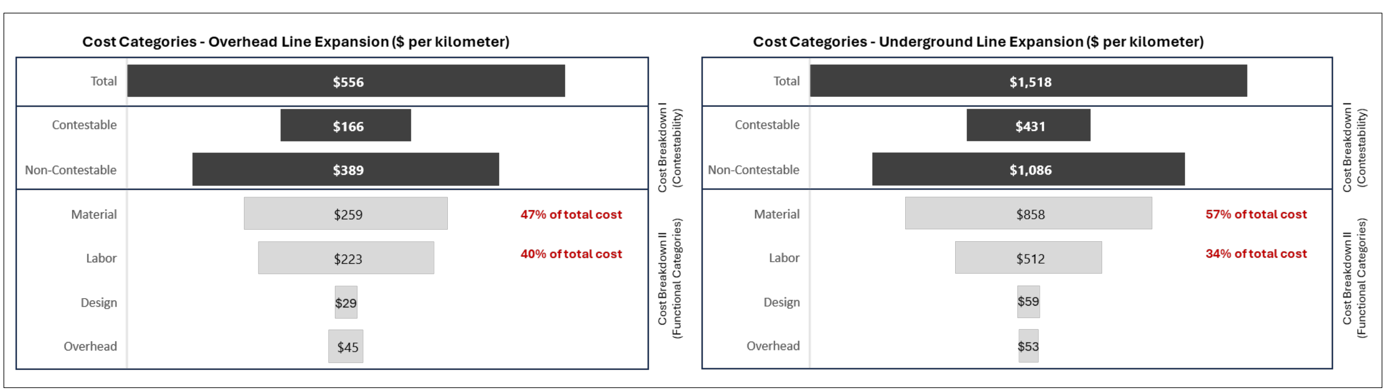


Figure 8 - Breakdown of overhead vs. underground primary line expansion costs ($k per kilometre)

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.

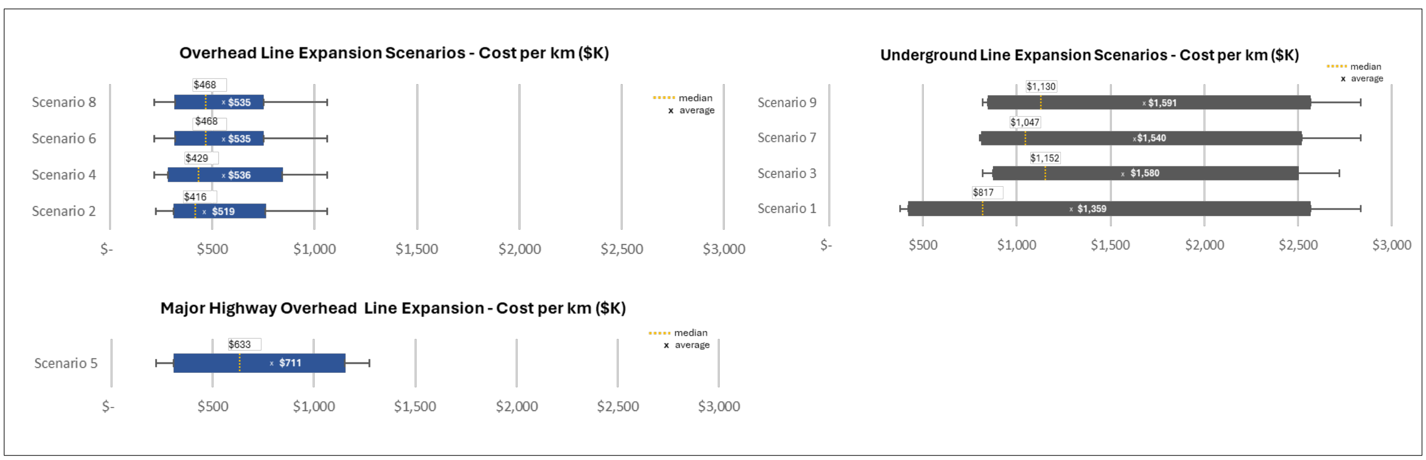
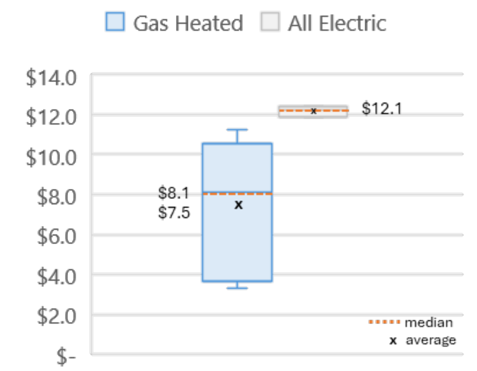


Figure 9 - Cost averages for participating LDCs broken down by Underground and Overhead Line Expansion Scenarios (costs in $k per kilometer)

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.

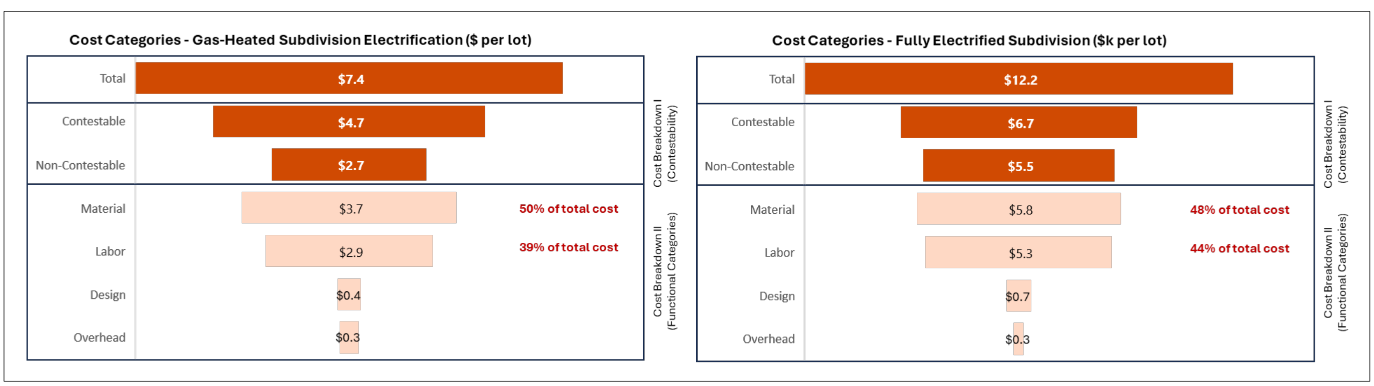


Figure 11 - Breakdown of gas-heated and all-electric subdivision electrification costs ($k per lot)

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.

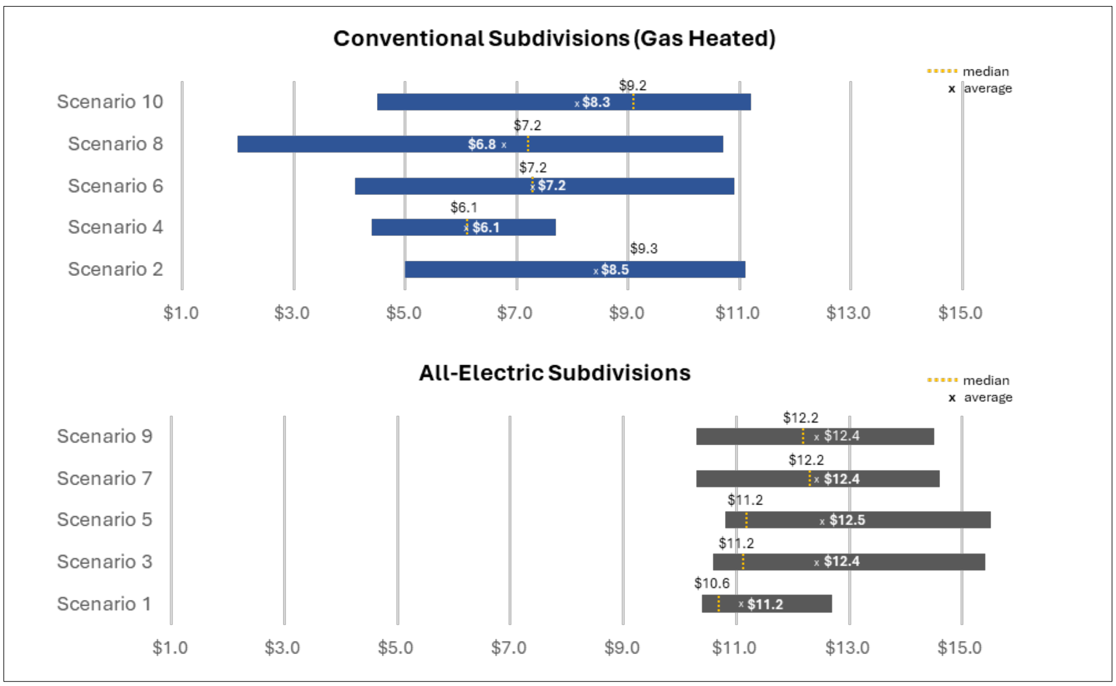


Figure 12 - Cost averages across participating electricity distributors broken down by degree of electrification per scenario (costs in $K per lot)

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.

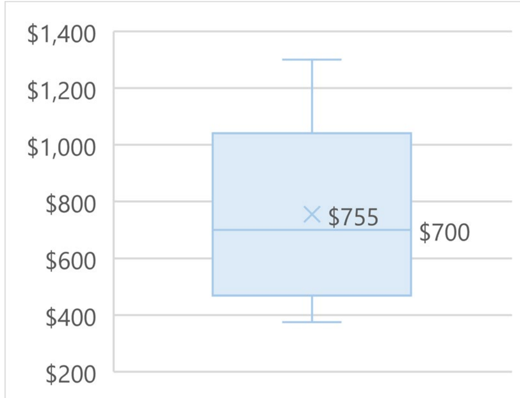
CapEx: Line Transformers - The APB Report also published data relating to line transformers. Notably, the cost of this component has increased ~$10.6 million per year, while the number of line transformers installed dropped by 641 per year over the five-year period. This corresponds to “the total combined 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.

Scenarios	Build Cost	Build Cost ($)	Average cost / lot	% of Build Cost (Avg)	Maximum cost/lot	% of Build Cost (Max)	Minimum cost / lot	% of Build Cost (Min)
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.

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[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

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[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

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[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.

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[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.

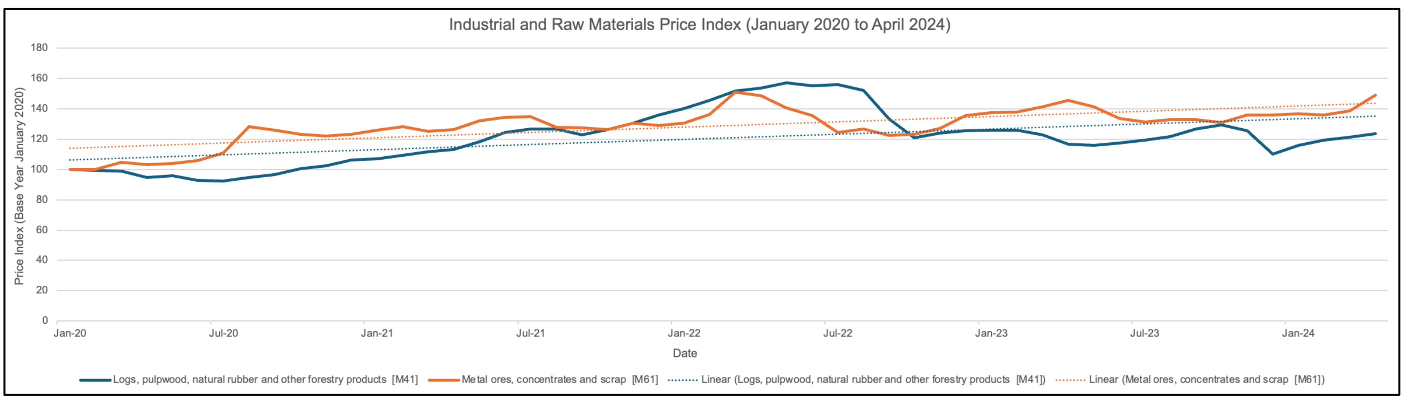

Figure 14 - Industrial and Raw Material Price Index (2020 - 2024)
Data Source: Statistics Canada Industrial and Raw Materials Price Index

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.

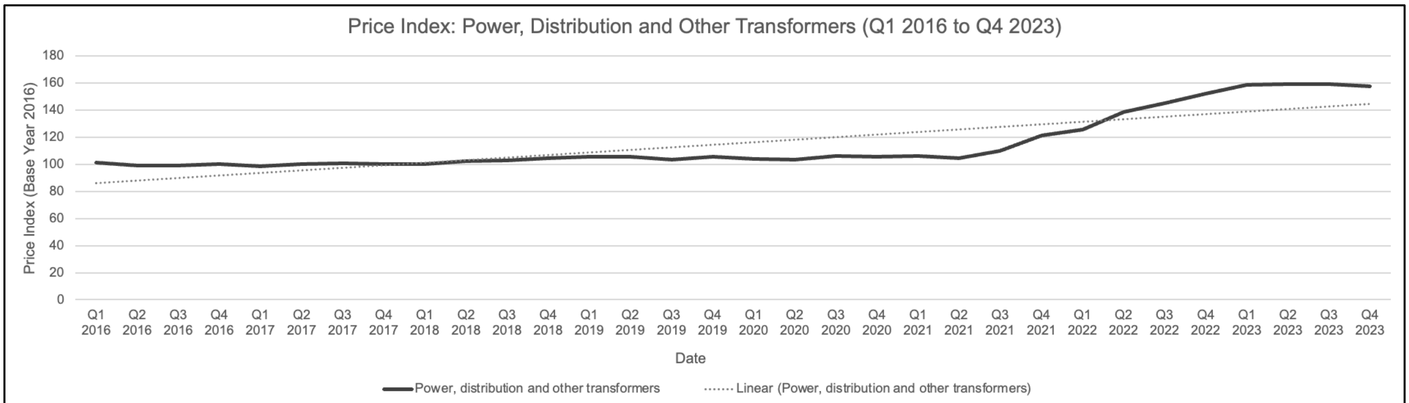

Figure 15 - Price Index for Power, Distribution and Other Transformers from 2016 – 2023
Data Source: Statistics Canada Machinery and Equipment Price Index

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*.

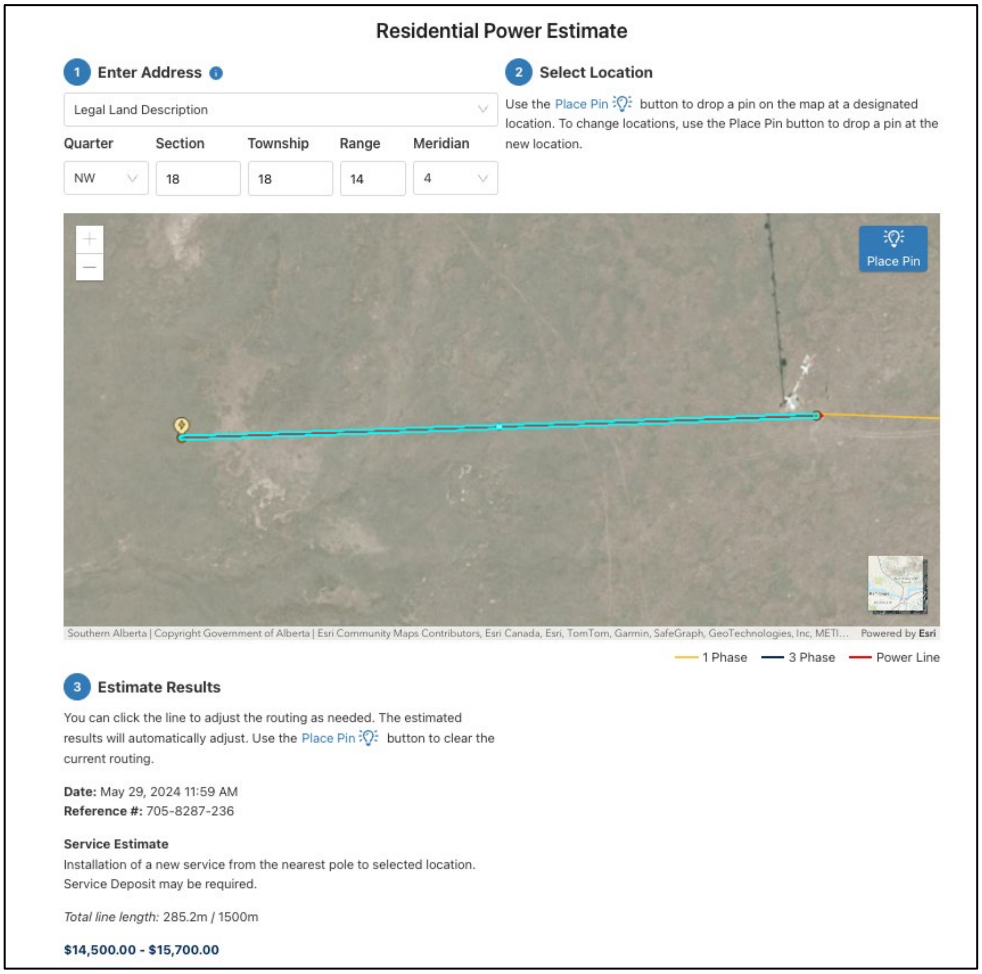

Figure 18 - FortisAlberta Service Estimator Output Sample
Source: FortisAlberta Service Estimator

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.*

- *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]
- *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:

  - Increasing the number of feeders available and feeder planning
  - Pre-emptively upgrading underground infrastructure to support increased loads
  - Creating positions for spare feeders so that, where necessary, new feeders can quickly be added
  - 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 Infill 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) 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	Material	Labor	Design	Overhead	Contingency			Contestable	Non-Contestable	Material	Labor	Design	Overhead	Contingency	Streetlighting
0									BOM per Scenario Please list out: 1. Material list 2. Quantity 3. Cost broken down by functional categories (material, labour, overheads)									
0																		
0																		
0																		
0																		
0																		
0																		
0																		
0																		
0																		

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?*

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

Developer Survey	
Category	**Questions**
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?
LDC Survey	

Category	Questions
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?
Category	**Questions**
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.