Powering Up: Solutions for Electricity Distribution Finance in Ontario

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Benjamin Dachis, Vice President of Research and Outreach

CLEAN PROSPERITY

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About Clean Prosperity

Clean Prosperity is a Canadian climate policy organization. We advocate for practical climate solutions that reduce emissions and grow the economy. Learn more at **CleanProsperity.ca**.

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Abbreviations

EV	Electric vehicle
IESO	Independent Electricity System Operator
GTA	Greater Toronto Area
LDC	Local distribution company
OEB	Ontario Energy Board
OEFC	Ontario Electricity Financial Corporation
PILT	Payment in lieu of taxes

Executive summary

To reduce greenhouse gas emissions and reduce the costs of transportation and home heating through electrification, electricity use will need to grow considerably in the coming decades. As they increasingly adopt electric vehicles and heat pumps, future customers will likely consume significantly more electricity at peak demand times than they do today.

Much attention has focused on the increased investment needed to generate the electricity to meet this increase in peak demand, such as in renewables and nuclear power. Relatively little attention has been paid to the investment needed to distribute more electricity to the customer.

This problem is particularly acute in Ontario, where significant population growth is adding to what is already the largest electricity customer base in Canada, and where there is heavy reliance on natural gas for home heating that will need to switch to non-emitting energy sources.

A particular problem in electricity distribution is how to pay for the infrastructure buildout needed to satisfy increased future demand. Distribution infrastructure growth is currently financed through a mix of debt and retained earnings from today's electricity users. Electricity distributors are subject to regulations that set their rate of return, and therefore their rates, as well as limits on their debt. These regulations have allowed for steady growth, and for the owners of electricity distributors — the province in the case of Hydro One, but mostly municipalities — to receive dividends that somewhat offset taxes and fees on residents, with the rest reinvested in the utility.

This paper shows how the need for significant investment in electricity distribution infrastructure creates an infrastructure financing gap, ranging between $2.2 billion and $8 billion, depending on assumptions, cumulatively over the next 15 years. This is a large, but still solvable gap if governments take action.

Regulators and the province must consider changes to the way municipal local distribution companies (LDCs) are financed and regulated in order to enable the infrastructure growth required to meet future increases in peak demand. Growing capital investment needs mean that public owners will be called on to inject capital, increasing pressure on municipal budgets and consuming scarce resources. LDCs and their municipal owners will need to consider various options to fill the financing gap, ranging from taxpayer support, charges to homebuilders, higher electricity rates, or non-municipal investors.

If municipal taxpayers or homebuyers support this infrastructure growth through property taxes or through connection fees charged to homebuilders, doing so comes at the expense of affordability. Investment in electricity distribution could also be pitted against other municipal infrastructure needs. Allowing for higher electricity rates can fill some of the financing gap, but again at the expense of affordability.

Municipalities and electricity distributors in Ontario could also look to non-municipal investors to fill the financing gap. However, the province collects transaction taxes that make significant non-municipal investments prohibitive. These taxes are no longer serving their intended purposes and are impeding investment in electricity distribution, and therefore emissions reduction.

For non-municipal equity financing to be economically viable, both the federal and provincial government should consider changing tax rules that are no longer fit for purpose. The provincial government should reduce or eliminate its transfer tax, and consider rebating departure taxes. The fiscal cost to the province of reducing this tax burden would be minimal and less than the long-term financing gap that Ontario LDCs face.

With strong regulatory protection and additional flexibility on long-term debt financing and private-sector investment, Ontario cities can finance electricity grid growth, keep rates low, and see a financial benefit from these key assets. Other approaches, such as reducing peak capacity needs, could also reduce investment needs.

This report shows that Ontario has the levers it needs to increase investment in local electricity distribution to meet the coming challenges. Armed with a sense of the scale of these challenges and the tradeoffs facing Ontario municipalities and LDCs, we can choose the best financing tools for the job.

In order for increased investment in electricity distribution to make sense, the province must make a commitment to decarbonize space heating and transportation. The financing gaps outlined here are a result of the increased investment needed for decarbonization of these technologies. The goal of reducing emissions and the reforms needed to increase investment opportunities in electricity distribution should move forward together.

Recommendations

Government of Ontario

1. Commit to decarbonization of home heating and transportation, consistent with the Independent Electricity System Operator's modelling of a net-zero future, to incentivize investment in electricity distribution infrastructure.

2. Reduce or eliminate the transfer tax that is imposed when non-municipal equity investment in LDCs exceeds a 10% threshold. The transfer tax is impeding LDCs' access to the capital they need to invest in new infrastructure that will meet the growing electricity needs of a net-zero economy. This transfer tax no longer has any policy justification.

3. Consider rebating all or part of the departure tax that is imposed when non-municipal equity investment in LDCs exceeds a 10% threshold. Rebating the departure tax could improve incentives for investment, but may have unintended competitive effects on other LDCs and create windfall gains for certain investors.

4. Ensure that regulatory bodies have robust practices in place to protect consumers and the public interest wherever there is non-municipal equity investment in an LDC. These robust regulatory protections should be applied equally to all LDCs, regardless of the ownership type.

5. New homes that can support electrified heating and vehicle charging require big investments in local distribution infrastructure. Work with the Ontario Energy Board (OEB) to reduce the obligations imposed on property developers to finance new distribution infrastructure. Consider longer-term tools to finance infrastructure growth that balance housing affordability and investment in electricity distribution, such as amortizing distribution assets over a longer time period, as is applied to natural gas infrastructure.

Ontario Energy Board

6. Investment in local electricity grids to facilitate a decarbonized Ontario entails uncertainty about future technology adoption. Uncertainty about the scale of investment needed, and the inherent riskiness of investment plans, is incompatible with the OEB regulatory system. Develop regulatory policies that encourage long-term investment, consistent with a mandate from the provincial government to decarbonize home heating and transportation.

7. Review the terms of any sale of a municipal LDC to ensure consumer and public interest protection. For example, ensure that LDCs are not over-leveraged and placing future consumers at risk. Exert strict discipline on the costs that LDCs propose for rate coverage.

8. Work with the Ontario government to develop long-term tools to finance LDC infrastructure growth, and carefully consider reforms to capital structure rules that inhibit LDC growth, such as adjusting deemed debt-equity ratios to encourage more investment.

Federal government

9. Federal tax rules define a municipal corporation as exempt from federal income tax if it has no more than 10% non-municipal ownership. In addition to a provincial transfer tax, federal tax rules require the province to collect a departure tax once non-municipal investment passes this threshold. Consider the pros and cons of raising the private ownership threshold at which LDCs lose their tax-exempt status. An increase to the threshold can aid in bringing in more investment, but could have unintended long-term consequences.

10. The province collects payments in lieu of corporate income taxes (PILTs) from municipally-owned LDCs to ensure a level tax playing field with private LDCs. Ottawa should consider financial support for the Province of Ontario to compensate it for lost PILT revenues from LDCs that become federally taxable entities.

Municipal governments

11. If senior governments eliminate or reduce taxes that discourage investment in LDCs, consider non-municipal investment partners to facilitate the build-out of electricity distribution, keep electricity costs down, and support municipal taxpayers.

Introduction

Canada's net-zero transition is likely to lead to significant growth in electricity demand. This likely pathway has spurred conversations about where to put new non-emitting generation sources and what kind of electricity generation is best suited to the future of Canada. But there hasn't been enough attention paid to the high anticipated capital costs associated with upgrading local distribution networks to serve the increased demand associated with a highly-electrified Canadian economy.

Technology cost reductions in non-emitting electricity sources, due to improvements in technology, are starting to emerge that should make the future of non-emitting electricity generation economically feasible. Between 2012 and 2022, the all-in cost of the U.S. electricity generation sector has grown by an annual compound rate of 2.3%, in line with or less than inflation. However, the transmission and distribution component has been growing by 6.8%, creating enormous challenges in delivering electricity (Campbell 2024). This study will focus on addressing the distribution investment and cost challenge.

Ontario is the most populous province in Canada, and the share of Ontario households that currently heat their homes with fossil fuels is one of the highest in the country. This means that the energy transition investment in distribution needed for heating electrification in Ontario is highest, both in terms of the absolute number of customers, which is also growing quickly, but also in relation to the potential increase in peak electricity demand, as households switch to electric heating and draw more electricity at the same time.

The scale of the investment needed in electricity distribution is intertwined with municipal politics. That is because the majority of electricity distribution assets in the province are owned by municipal governments. They have created subsidiary corporations that provide dividends to the municipalities, thereby defraying local property taxes or the need for other sources of revenue to fund municipal services. Hydro One Networks, 47% owned by the provincial government, operates the province's largest network of distribution assets, mostly in rural Ontario, and also provides dividends to the province. While the revenue from these dividends is a minor share of total revenue, it is still an important source of flexible dollars that allow municipalities to avoid raising taxes or incurring other costs. In other words, municipalities will be very reluctant to do anything to compromise this revenue.

In addition, electricity affordability has been at the center of Ontario politics for generations. Any material increase in electricity rates to finance future grid growth would come at significant political cost. Another pressing issue is that housing is increasingly unaffordable. Ontario local distribution companies (LDCs) rely on upfront financing for electricity distribution expansion from housing developers, who may pass these costs onto homebuyers. The Ontario Energy Board (OEB) is leading a consultation on this concern, and the province intends to introduce new legislation to address it.

These imperatives — the energy transition, energy and housing affordability, and the need for government revenues to keep other fees and taxes as low as possible — are now colliding.

Maintaining affordability and enabling investment

If cities maintain the status quo with respect to the ownership structure of LDCs and the dividends they draw from them, and if they aren't willing to sacrifice electricity affordability, Ontario's attempts to reach net-zero emissions through electrification will result in a capital financing shortfall over the next 15 years. How will municipalities finance this? We outline various scenarios of the size of the financing gap, which is a subset of the actual total investment needed, ranging from about $2 billion and $8 billion between 2025 and 2040.

One approach is to ask taxpayers to finance the energy transition. Decisions from the City of Toronto foretell a future of higher property taxes or other user fees and/or less investment available for other municipal infrastructure priorities. In June 2024, Toronto City Council approved hundreds of millions of dollars of taxpayer support over a decade to Toronto Hydro, in both equity investment and a lower annual dividend that Toronto Hydro delivers to the city. The City of Toronto's Council presentation states that it will offset the equity investment by maximizing use of development charges on developers, who may pass them onto homebuyers, and leveraging other capital funds. That means Toronto City Council has decided to increase housing costs through increased reliance on development charges and to devote its scarce capital resources to invest in electricity distribution infrastructure instead of other municipal priorities. This is an implicit trade-off: Council has decided that electricity infrastructure investment is a more valuable investment of taxpayer dollars than other requests that do not meet the bar for municipal spending authorization.

How will other cities make this choice? In our baseline scenario, under current growth forecasts and regulatory limits, the total LDC financing gap is around $4.7 billion over-and-above many billions more of equity injections. Another approach to filling that gap is to increase electricity rates, thereby collecting equity for reinvestment in the grid. However, electricity distribution companies face regulatory constraints on rate setting. Any further increase in the regulated rates of return are likely to result in higher electricity prices for consumers; a politically difficult outcome in any circumstance, especially in Ontario.

Other alternatives include regulatory changes that enable LDCs to increase their reliance on debt to finance growth. This would allow for greater financing via debt, albeit at potentially higher risk, and therefore higher capital costs, and less financial resilience in the future. These potential changes are all now part of another [ongoing OEB review](#).

The higher upfront capital investment cost of electric heating and vehicles, compared to their fossil-fuel counterparts, is a fundamental challenge of the energy transition. Carbon pricing is meant to address that problem by increasing the operating cost of emitting technologies. The alternative approach to incentivizing emissions reduction, in the absence of carbon pricing, is to drive down the cost of electricity infrastructure investment or electricity-consuming devices. These regulatory changes above would also necessitate a directive from the province or regulator to reduce emissions in order to make these investments financially prudent.

Governments should consider all of the above options, and should also look at other approaches to reduce the needs for investment in electricity distribution, such as with new models of distributed system operation. If, after these options are exhausted or deemed too high a cost in any other sense (e.g. politically, or at the expense of emissions reductions), another alternative Ontario municipalities should consider is non-government equity investment. That could range from pension funds, to other energy providers, to federal or provincial infrastructure funds. Other equity investors may be willing to take a lower immediate dividend in favour of longer-term, steadier returns that a rate-regulated sector offers. If so, these investors may be able to solve this energy investment problem and take on investment risks that municipal shareholders may be less willing to accept.

A future of lower-emissions infrastructure

Current provincial and federal tax rules and regulatory limits mean that municipal governments cannot independently finance the capital investments or increase debt issuance in their local distribution networks that will be required in a high-electrification future. Toronto had no choice but to support Toronto Hydro with taxpayer equity investment if it wanted to invest now. That is because federal and provincial governments impose taxes on selling more than a 10% stake in LDCs. This makes any non-municipal investment uneconomic.

It is time for the provincial government to eliminate or reduce the tax burdens that create barriers to investment. It should fully eliminate the transfer tax that municipally-owned companies pay because the policy objectives these taxes were originally intended for — paying down excess debt from the electricity sector buildout decades ago — are no longer valid. Investors of all kinds should have a level playing field for investing in Ontario's LDC sector. The provincial government should create time-limited, but comprehensive, exemptions or rebates on the taxes that impede sales of LDCs. The OEB will also have a role to ensure that consumers and homebuyers are protected. The OEB plays a role now in protecting consumers from decisions by both publicly and privately owned energy distributors seeking to put excess costs on ratepayers. The OEB must continue to be, and be seen to be, a strong defender of the interests of electricity consumers.

Ultimately, decisions about investment in Ontario LDCs will come down to municipal governments. Private investors may be willing to pay a premium on LDC equity relative to how municipal governments value their equity investment. Once tax barriers are removed, cities can choose how they want to prioritize options for maintaining revenue in the long term. It will avoid electricity investment crowding out other municipal priorities and allow for upfront funds to invest in those other priorities, while maintaining control of their LDCs, and fostering the energy transition.

Building emissions and electrification

Key takeaways

- Buildings are a key source of Canada's emissions. Heat pumps are a practical solution to providing non-emitting heating. However, heat pumps draw a considerable amount of electricity during the coldest hours of the year.
- Canadian forecasts foresee significant increases in peak electricity demand to meet emissions reductions goals.
- The global and Canadian outlook for electricity distribution infrastructure foretells significant distribution infrastructure costs to meet future peak capacity needs in a net-zero world.

The greenhouse gas emissions from buildings represent a significant share of Canada's total emissions. Most studies indicate that increasing the use of electricity is at the center of any plan to reduce emissions.

Buildings in a net-zero Canada

Total emissions today

Canada's buildings sector is responsible for 89 megatonnes, or 13%, of Canada's total 2022 emissions. In Ontario, that share nearly doubles, with buildings responsible for 25% of the province's emissions, the second largest source behind transportation. Emissions from residential buildings account for a little more than half, with commercial and institutional buildings not far behind.[1] For residential buildings, space heating is the largest contributor to emissions, driving about 77% of total emissions. Water heating represents 22% of total emissions, and appliance usage adds a negligible amount.

Natural gas provides the majority of the energy consumed in Ontario residential and commercial uses, mostly for heating. Therefore, most of the emissions from buildings in Ontario arise from natural gas combustion. The share of Ontario's total emissions that comes from housing has been rising as emissions from the electricity generation and industrial sectors have fallen significantly.

[1] This analysis excludes emissions from industrial processes and focuses on energy use for the purpose of personal comfort.

Pathways for emissions reduction

Nearly all major studies of pathways for reducing emissions in Canada result in increased consumer use of electricity, particularly for home heating. Switching home heating to electrified heat pumps that are much more energy efficient than natural gas heating can reduce energy consumption at most times, except for the coldest days of the year. However, consumers demand home heating the most at these coldest hours. These few coldest hours of the year are what will drive peak electricity demand, and therefore investment to meet this demand.

Home heating and cooling

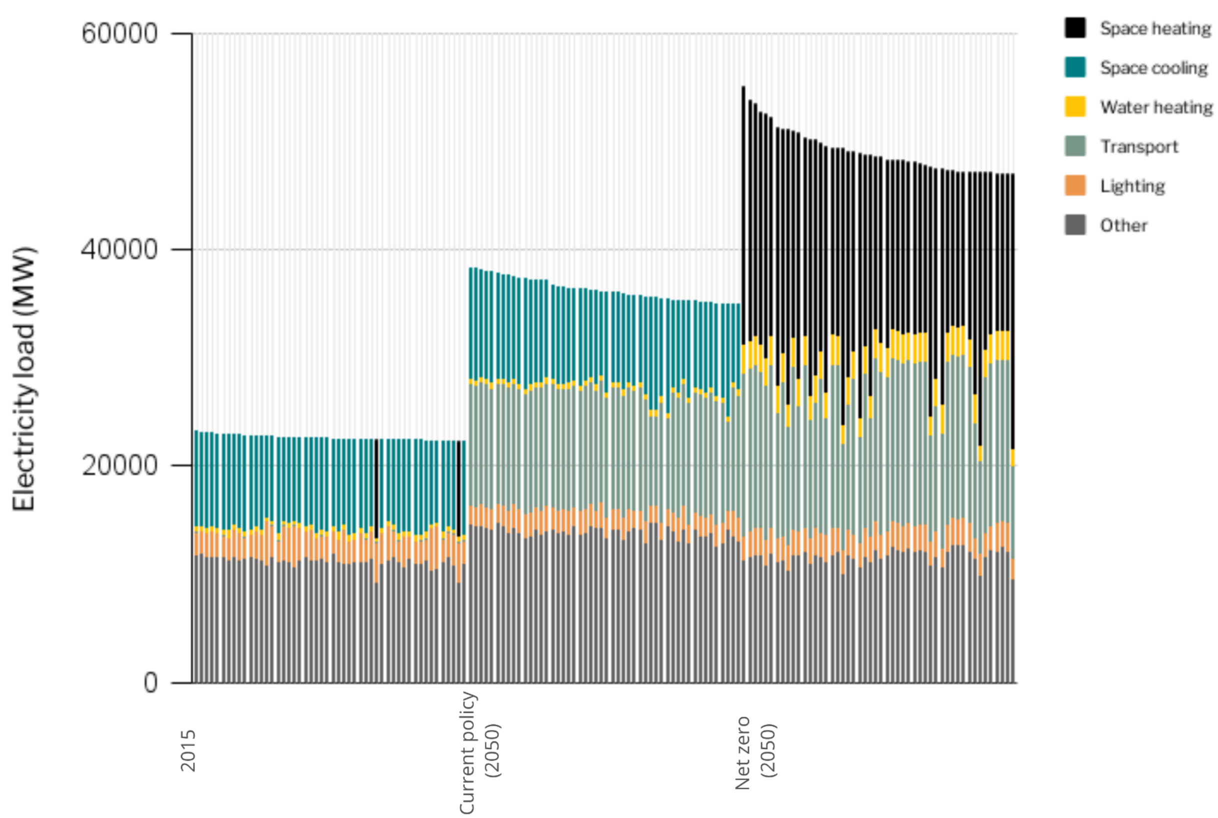
The most promising technological alternative to combusting natural gas for home space heating is a heat pump. A home heated with natural gas uses in-home ducts to transport heat from a furnace to various rooms. Heat pump systems, in contrast, work like reverse-air conditioners and use refrigerants to transfer ambient heat from outside to the inside. Like air conditioners, heat pumps are powered by electricity. Heat pumps also work as air conditioners in the summer. They are highly energy efficient in many circumstances, able to transfer multiple times the amount of heat than the amount of energy used to conduct the transfer.

The reason for this energy efficiency is that even in cold climates, there is always ambient heat that can be captured, and it takes less energy to transfer heat than to generate heat (for example, through combustion or electrical resistance). However, the efficiency in collecting ambient heat falls once temperatures fall considerably below 0 degrees Celsius. At these temperatures, many heat pumps revert to using the resistive heating technology of traditional baseboard heating, which converts electricity directly into heat at an efficiency level comparable to modern natural gas furnaces.

The consequence of this relationship between heat pump efficiency and temperature is that on the coldest days of the year, if consumers do not have backup natural gas furnaces and rely entirely on heat pumps, their total energy consumption on the coldest days of the year is significantly higher than on other days. Peters et al. (2024) finds meeting these peak demands is a major driver of a significant rise in end-use electricity, particularly in Ontario and Alberta, if these provinces are to reach net-zero emissions.[2] They find that peak Ontario demand will more than double from 2015 levels to 2050 (Figure 1), growing from 23,000 MW to 55,000 MW. Indeed, in subsequent analysis that incorporates potential grid impacts of a cold winter, peak demand could grow to over 60,000 MW.

[2] Provinces with milder weather or that currently have widespread deployment of electric resistance heating will see modest increases in peak demand in Peters et al. (2024) forecasts. Alberta's peak electricity demand quintuples in their net-zero forecast.

Figure 1: Peak electricity load in the highest 50 hours of the year in Ontario, 2015 and 2050, under current and net-zero policy



Source: Peters et al. (2024).

Further, the consumer-facing component currently utilizing the distribution grid faces outsized growth. Industrial consumers, a large share of the "other" consumption in Figure 1, that sees little to no growth in net demand, are often directly connected to the transmission system and consume high-voltage electricity. Therefore, the growth of the distribution system-connected peak demand starts from a base of half of Ontario's peak demand to becoming more than 80% of total peak demand.

In addition to these studies forecasting increased use of electricity to meet home heating needs, other studies point to alternative fuels. Guidehouse (2023), in a study commissioned by Enbridge, points to two potential low-cost scenarios for Ontario: an energy system built around electrification of home heating, and a diversified system built around a mixture of electricity and hydrogen. Its electrification scenario points to a more than tripling of peak electricity demand between 2019 and 2050. Indeed, its diversified system results in a more than doubling of peak capacity. Therefore, regardless of the exact pathway that emerges, a consensus has emerged that Ontario will see a significant increase in peak electricity demand to meet a net-zero emissions target.

Other home electrification needs and heating options

In addition to using electricity to reduce Canada's reliance on fossil fuels for heating, transportation needs will be electrified. Many users of electric vehicles (EVs) will charge their vehicles at home and place large strains on their local grid. Current government policy is likely to result in electric vehicles being the largest driver of home electricity usage growth (see Figure 1). However, these electric vehicles are likely to take advantage of differential charging times. That means they are less likely to result in a strain on local electricity grids than the use of heat pumps to satisfy home heating requirements. Home heating does not have that luxury to the same degree yet. Peters et al. (2024) shows that despite consumers' ability to charge at differential times, EV charging increases the utilization of peak electricity capacity, but does not dramatically reduce the peak forecast demand in a net-zero scenario. However, Bailey et al. (2024) show that centralized control of EV charging can reduce peak distribution grid strain.

Other technology could reduce the strain of heat pumps on the electricity grid (McDiarmid 2023). For example, the efficiency of ground-source heat pumps is not affected by extreme cold temperatures. However, the upfront cost of current ground-source heat pump technology is considerably more than air-source heat pumps, and may not be feasible in all locations. Other options include the integration of batteries with air-source heat pumps, integration with hot water heaters and other thermal sources, and other technologies. All of these technologies are capital investments currently borne by the customer that have ramifications for the investment decisions of the local distribution grid operator.

Investment pathways

These pathways for the overall increase in peak electricity demand have ramifications across energy systems, both globally and domestically.

The global outlook

A number of global energy outlooks point towards electricity investment as the fundamental driving force behind emissions reductions. The vast majority of the global consumer-driven demand for net-zero emissions technology will come via electric vehicles (BloombergNEF 2024). There will be global demand for heat pumps, concentrated in colder countries like Canada.

The other key driving force of investment is on the supply side. The single largest sector for investment growth is in power grids, to facilitate the transportation of electricity generated from non-emitting sources of electricity, such as nuclear and renewables. These power grid investments include everything from inter-regional transmission to local distribution services. These local distribution needs include local transformers, additional local cables, substations, and much more.

Around the world, private investment in electricity distribution is common, but mixed ownership, between the state and private interests, is common as well. In the U.S., 80% of power travels over privately owned transmission and distribution lines. In New Zealand the electricity system is partly owned by local governments and partly privatized; and in Australia the system is partly owned by state governments and partly privatized. In the United Kingdom, all of the 14 districts of service in the country are serviced by privately owned distribution companies (Robins 2017). In all these countries, private ownership is overseen by an economic regulator that oversees the setting of rates. Canadian pension funds are often major investors in these international utilities.

The Canadian outlook

These global investment outlooks are reflected in some Canadian examples of the investment need forecast, specifically for electricity distribution systems. For example, Guidehouse (2024) recently conducted a review of the increased need for investment in Alberta's distribution system solely due to the increased use of electric vehicles. As this assessment does not include the potential impact of using heat pumps for home heating, the estimates are likely to be on the low end. Guidehouse (2024) estimates that Alberta's major electricity distributors will need to increase their investment spending to a sustained $2.6 billion per year in a scenario in which the province reaches net-zero emissions. However, allowing more centralized control of electric vehicle charging to balance charging use with solar generation reduced investment needs to $1.8 billion per year. Whichever scenario occurs, these investment levels are still a significant increase from the approximately $1 billion in annual capital investment the four largest electricity distributors in Alberta made in 2022.[3]

A recent Ontario study from the Electricity Distributors Association (2024) comes to a similar conclusion. It forecasts that annual capital expenditures to meet the increased peak capacity will result in a doubling of annual capital expenditures relative to current levels, from about $3 billion to $6 billion by 2045, and more by 2050. It comes to this conclusion by taking the Independent Electricity System Operator (IESO) Pathways to Decarbonization (2022) peak demand forecast for maximum winter load and linking that to the historical relationship between distribution sector investment and maximum demand. The Electricity Distributors Association (2024) shows there is

[3] We calculate the total 2022 capital additions in Alberta's electricity sector from the Alberta Utility Commission filings from Fortis, Atco Electric, Enmax and Epcor.

a historical linear relationship between peak customer demand and capital investment needs. Every extra megawatt of capacity increase results in about $100,000 in annual additional capital investment. The IESO forecasts that in their decarbonization pathway, total winter peak capacity will increase to about double today's summer peak by 2040 and will be about 2.4 times the current peak capacity by 2050. The forecast also notes that these investment amounts could be reduced considerably by changing how utilities operate, away from passively managing infrastructure between consumers and generators, towards a model in which generation is more widely distributed across the province and integrated into the distribution system.

Distributed system operator

Distributed system operations can significantly reduce future electricity investment needs by enabling more efficient energy use and generation. By decentralizing power production, such as through localized renewable energy sources like solar panels and wind turbines, communities can harness and utilize energy closer to the point of consumption. This reduces transmission losses and lessens the burden on centralized grids, decreasing the necessity for large-scale infrastructure investments. Additionally, distributed systems can leverage smart technologies and demand response strategies to optimize energy usage during peak times, further alleviating the need for costly new power plants. As a result, a more resilient and flexible energy landscape emerges, ultimately lowering the overall capital required for future electricity needs.

Distributed system operations differ from traditional LDCs primarily in their structure and approach to energy generation and management. Local distribution utilities typically operate as centralized entities that manage the delivery of electricity from large power plants to consumers through a fixed grid system. Their operations focus on maintaining infrastructure, managing outages, and ensuring a steady supply of electricity.

In contrast, distributed systems decentralize energy production, allowing individual consumers, businesses, and communities to generate their own power using local renewable sources. This shift encourages a more interactive energy landscape where users can become both producers and consumers — often referred to as "prosumers." As a result, energy generation is more localized, reducing transmission losses and enhancing grid resilience. Moreover, distributed systems often leverage advanced technologies, such as smart meters and energy management systems, enabling real-time monitoring and optimization of energy usage. This fundamentally transforms the role of local utilities from mere providers to facilitators, supporting a more dynamic, flexible, and sustainable energy ecosystem. Such a fundamental shift is possible, but the scale of its potential application remains unclear, so is out of scope of the modelling done here.

Electricity distribution in Ontario

Key takeaways

- The ownership of Ontario's electricity sector is split across generation, transmission, and distribution. There are 54 mostly small local electricity distribution companies in Ontario as of 2024. The province of Ontario partially owns the largest: Hydro One. Most of the rest are owned by municipalities and the few largest LDCs represent most of the customers.
- The Ontario Energy Board regulates LDCs, determines the appropriateness of investments ratepayers will cover, and sets a regulatory rate of return for LDCs, all to set economically appropriate electricity rates.
- All levels of government have a fiscal policy relationship with electricity distribution companies, either through direct dividends, through the tax system, or through payments in lieu of taxes, when companies are otherwise not taxable.
- The province collects taxes on municipal LDC transactions when non-municipal investors own more than 10% of the company. The Province of Ontario is reviewing these taxes, which were meant to pay off decades-old debts, with a decision on reform imminent.

Each provincial electricity system is unique in its mix of ownership, both public and private, and the degree of integration from generation to end distribution. Ontario has a particularly unique mix.

Ontario's electricity sector

Ontario's electricity sector ownership is broken into three distinct categories. Since the breakup of Ontario Hydro in the 1990s, large-scale hydroelectricity and nuclear generation has been dominated by Ontario Power Generation and Bruce Power. However, other companies also operate in the electricity generation market with renewable and fossil fuel-powered facilities. Hydro One provides nearly all the transmission between large generation stations and local communities. Hydro One provides electricity distribution in much of rural Ontario, and municipally-owned distribution companies provide local service in much of the rest of urban, suburban, and some rural areas (see Box 1 for a summary of the electricity life-cycle from generator to customer).

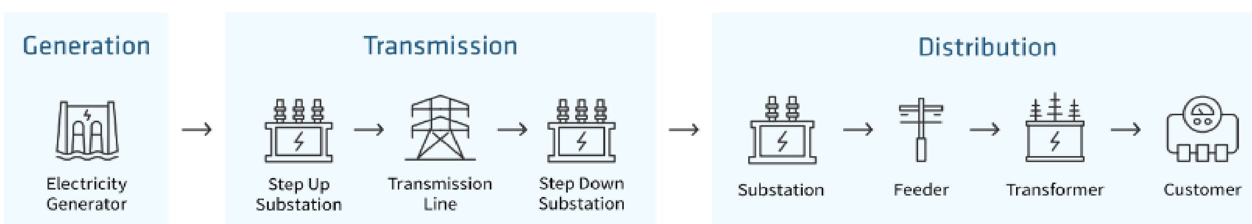
Box 1: The current electricity life cycle

Electricity generation in Ontario is still mostly produced at large generating sites. The electricity is then converted on-site at a step-up substation to high voltage, which is the most efficient way to transmit electricity over large distances. The most visible feature of transmission infrastructure are the Hydro One high-voltage wires that traverse the province in dedicated corridors.

Hydro One is also responsible for infrastructure that converts the voltage from generating stations to transmit it, then again for step down stations to produce voltage levels appropriate for local distribution. These substations are major investments and are located across the province. Local electricity companies then have a nearby interfacing substation. Some local substations are the size of large buildings.

Distributors then send electricity across their local communities, usually with overhead electrical wires adjacent to streets. Local distribution companies operate a series of transformers (for example, housed in large boxes alongside or underneath streets, or at the top of distribution poles) that convert the electricity to the correct voltage to feed into residential or small commercial addresses. Local distribution companies are usually responsible for covering the final infrastructure from the electrical poles to a customer's electricity meter.

Figure: The electricity generation, transmission and distribution chain



Source: Flanagan and Poirier (2023).

Generation and transmission investment

Much has been written about Ontario's generation and distribution needs. For example, Frank et al. (2024) point to the large potential supply gap that could occur in Ontario if ambitious climate policies encourage mass adoption of electrification. They point to the potential role of nuclear power as filling in this gap. Other studies, such as from the IESO, show significant growth of a wide variety of non-emitting electricity generation sources. The IESO forecasts that 20,000 MW of installed capacity today will still be operational in 2050. A further 69,000 MW of capacity will need to be installed to meet Ontario's net-zero emissions target. The IESO is also conducting a review of transmission needs for major cities, such as Toronto.

Distribution

As of 2024, there are 54 LDCs regulated by the Ontario Energy Board. This is down considerably from the late 1990s when there were hundreds of LDCs, with most LDCs being departments of their respective municipal governments. LDCs range in geographic size from serving a very small built-up area in a small municipality, to covering single (such as in London, Ottawa, or Toronto) or multiple cities (Enova in Waterloo Region, Elexicon mostly in the eastern Greater Toronto Area), to the nearly province-wide coverage across much of rural Ontario for Hydro One.

Many municipal LDCs have grown through inter-municipal mergers. The most notable example of this is Alectra, which combined many of the municipal LDCs in the northern and western Greater Toronto Area (GTA). It has now grown to become the third-largest LDC behind Toronto Hydro and Hydro One, measured by total rates (Table 1). These three LDCs represent about 75% of the province's total asset base for LDCs, with over 50 LDCs representing the other quarter of total assets. The share of total customers is more widely spread out, however, with the three largest LDCs representing 62% of total customers connected. The total customer metric counts large customers (such as apartment complexes or industrial customers) the same as small residential customers.

Table 1: Ontario LDCs by share of total rate base and number of customers, 2023

Company Name	Total Rate Base ($ millions)	Share of Rate Base	Total Customers	Share of Total Customer
Hydro One Networks Inc.	9,564	39%	1,458,062	27%
Toronto Hydro-Electric System Limited	5,177	21%	792,732	15%
Alectra Utilities Corporation	3,629	15%	1,082,646	20%
Hydro Ottawa Limited	1,322	5%	364,334	7%
Enova Power Corp.	528	2%	162,022	3%
Elexicon Energy Inc.	474	2%	176,725	3%
London Hydro Inc.	395	2%	167,081	3%
$100 to $300 million in total rate base (14 LDCs)	2,281	9%	783,367	14%
Less than $100 million in total rate base (33 LDCs)	1,075	4%	468,195	9%

Source: Ontario Energy Board Open Data. Percentages may not add to 100% because of rounding.

The vast majority of Ontario LDCs are owned by municipal governments, either in whole or with 90% ownership or more. Major private energy companies such as Enbridge and Fortis[4] have minority ownership stakes of 10% (the maximum allowed before triggering transaction taxes discussed below) in a few small LDCs. EPCOR, owned by the City of Edmonton, owns the electricity distributor in Collingwood. Alectra has a small stake owned by OMERS, a major Canadian pension fund that originally held a share in a predecessor of Alectra, as do other pension funds in other small LDCs.

The only major change in the type of ownership of an Ontario LDC was the partial sale by the provincial government of Hydro One (both transmission and distribution) in 2015. Previous analysis by Dachis and Balyk (2021) shows that Hydro One saw faster growth in direct administrative expenses between 2006 and 2015 than other Ontario LDCs. After its privatization,

[4] Fortis also directly operates some small LDCs.

those costs consistently fell. The savings that occurred after the privatization were in the range of 36% of administrative costs between 2015 and 2019, while other LDCs saw administrative costs rise by 5% over the same period. They also show that if other municipal LDCs saw similar savings resulting from private investment, total annual savings would be 10% of total distribution system costs.[5]

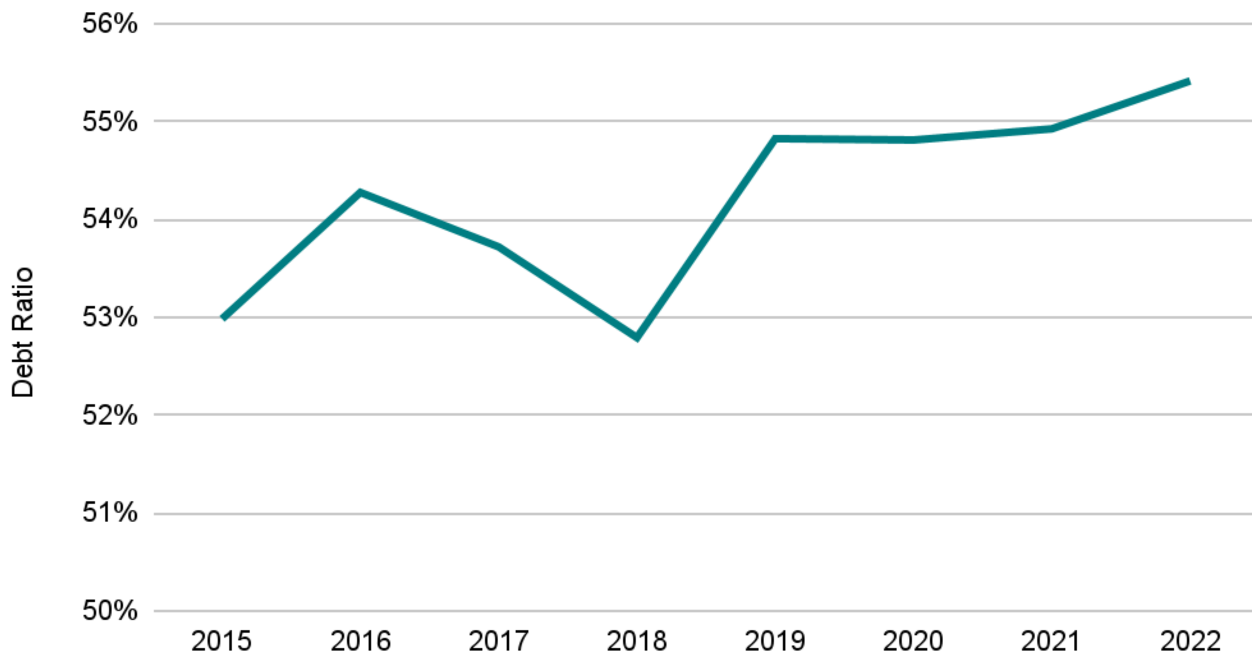
Regulation

The operations, particularly capital plans and rate setting, of Ontario LDCs are closely overseen by the Ontario Energy Board. The OEB began as an economic regulator of the natural gas system. In the 1990s, as the province spun out its ownership control of the electricity sector, the OEB's mandate expanded to include electricity distribution and transmission and some roles in electricity generation. The core mandate of the OEB is to protect consumers and ensure the sustainability of the energy sector. LDCs regularly report their capital investment outlook for OEB approval on annual rate updates, with more intermittent full-scale reviews of the capital plans of LDCs.

This report focuses on the OEB's role in regulating LDC rates and capital mix. The OEB assumes a capital mix that is no more than 60% debt (56% long-term debt, and 4% short-term debt) in setting rates that distributors can charge.[6] These kinds of ratios are a globally accepted regulatory principle for utilities that protect ratepayers while promoting growth, but global differences do emerge. Debt-equity ratios ensure that LDCs do not have so much debt that cash flows from ratepayers cannot cover those costs. Debt rating agencies, which influence the market cost of debt, also closely watch these debt ratios and too high a debt level would result in credit rating downgrades and a higher cost of debt. On the other hand, too low a debt ratio would mean that the capital structure is being financed at too high of a weighted average cost of capital, and that leads to higher rates than are required.[7] The OEB collects data on the capital structure of Ontario LDCs along with other data used throughout this report. The trend of Ontario LDCs in aggregate is that their long-term debt has been rising since 2018 with the province-wide long-term debt level approaching the deemed assumption of 60% of capital (Figure 2).

[5] The extent to which these savings flow to shareholders versus customers is determined by OEB policy.
[6] Other jurisdictions use slightly different ratios. The OEB commissioned an extensive report on the optimal capital structure of LDCs (London Economics International 2024). The report recommended no change from this ratio, as the alternative options all create downside risks.
[7] Debt costs are almost always lower than the regulated return on equity. A low debt ratio means that companies are foregoing debt that could generate investments that deliver higher returns on equity.

Figure 2: Long-term debt as share of debt-equity financing, Ontario LDCs, 2015-2022



Source: Ontario Energy Board yearbooks. Note: The OEB reports 2022 data in a slightly different format. To create a consistent time series, we apply the rate of growth of debt in 2022 relative to 2021 to figures reported in the 2021 Ontario Energy Board yearbook.

Another key element of protecting ratepayers is a regulated return on equity. The OEB sets the current return on LDC equity investment at around 9%.[8] Too high a rate of return on equity would mean that companies could increase electricity rates beyond what would be deemed a fair rate of return, therefore increasing costs for consumers. Too low a rate would drive away globally mobile capital investment seeking greater returns. The concept of the regulated return on equity allows for a level of profit that an LDC can generate in a way that balances affordability for customers but creates the incentive for LDCs to invest.

[8] This same capital financing report commissioned by OEB staff (London Economics International 2024) recommended only minor changes to the allowed return on equity. The OEB has yet to decide on this matter.

The cost and performance of electricity distribution in Ontario

LDCs earn their revenues primarily from end consumers of electricity. However, LDCs also collect revenues for expansion of the electricity grid from homebuilders.

The consumer cost of electricity distribution

The typical bill for Ontario electricity consumers depends on their utility. Each utility must receive OEB approval for their costs of capital and operations. Once approved, the utility calculates how to share those costs across its customers, such as via fixed monthly amounts or a per kWh basis. For a Toronto Hydro customer in the winter of 2024, transmission and distribution charges made up about 40% of the total bill, before considering taxpayer support with government rebates (Table 2). According to Bishop et al. (2020), distribution costs are about twice the size of transmission costs. That means that for the typical Toronto Hydro customer, depending on whether the government rebate is included, distribution costs are about one-quarter to one-third of the overall electricity bill.

Table 2: Sample bill for Toronto Hydro customer, winter 2024

Bill Category	**Total**
Electricity Usage	$72.10
Transmission and Distribution	$63.16
Regulatory Charges and Taxes	$22.67
Government Rebate	$-26.97
Total Bill	**130.96**

Source: Ontario Energy Board bill comparison. Note: Assumes average energy use (700 kWh), using tiered rates.

Electricity distribution expansion and housing

In addition to the cost to consumers, homebuilders pay a portion of the upfront cost of new electricity distribution infrastructure. The OEB produces a *Distribution System Code* which lays out guidelines on how utilities calculate the costs of new connections. For an expansion of the distribution network, in which a single developer's, or group of developers' projects are the clear beneficiaries of a new investment, the two main sources of upfront financing are a capital contribution and an expansion deposit (see OEB 2024 and Box 2). The OEB is currently reviewing this system, which has faced criticism that developers, and therefore homebuyers, to the extent costs are passed through, bear disproportionate risk of financing electricity system growth. On October 21, 2024 the province announced an intention to introduce legislation to implement the findings of the OEB report to the Minister.

Box 2: Housing expansion and electricity distribution

The potential capital contribution a developer or group pays is the net amount of capital construction costs and ongoing maintenance and operating costs minus forecast revenues over up to 25 years. If forecast costs are more than forecast revenues, the developer pays an upfront contribution they never receive back, that goes to the LDC to finance growth.

If forecast costs are less than forecast revenues, the developer must pay the higher of an upfront deposit for either the full 25 years of revenue or the full capital costs and long-term maintenance costs. Developers are supposed to receive these deposits back if they can connect all the customers who are going to benefit from the distribution system expansion over a five-year period. However, this is often not economically feasible for the construction of new subdivisions. Electricity distribution infrastructure is often planned for decades, and new construction of the homes often extends well beyond five years. The result is that developer deposits are forfeited to LDCs.

There is only anecdotal evidence from specific examples of the costs to homebuilders of this system. One recent example features a developer of a new subdivision facing an $80 million distribution expansion project to service a major new subdivision with well over ten thousand residents planned. However, as it can only build and sell 750 to 1,000 units per year, the developer faces a large upfront cost of a forfeited deposit. It estimated the total cost per homebuyer of this charge of $20,700 (BILD 2024). This includes both direct capital cost, but also the additional interest cost the developer faces of taking out debt to finance the deposit. These costs may eventually be lower, partly because of the potential for competing alternative LDC options.

This financing system applies only to system expansion in which new homes are the clear beneficiaries of new distribution infrastructure. There are additional distribution enhancement costs attributable to gradual expansion of electricity usage within cities, such as for infill development and more electricity demand. These costs are borne by customers as a whole through the LDCs’ rate base.

Figure: Capital contribution system for Ontario LDCs

Capital contribution	=	Capital costs	+	Ongoing operation & maintenance costs	−	Forecasted revenues
		All capital costs associated with the connection over the **connection horizon**		All incremental operation & maintenance costs and taxes associated with the connection over the **revenue horizon.** Total forecasted customer additions over the **connection horizon.**		Distributor revenues over the **revenue horizon.** Total forecasted customer additions over the **connection horizon.**

Source: OEB 2024.

The fiscal relationships of electricity distribution

The three levels of Canadian government — municipal, provincial and federal — all have a financial stake in the performance of electricity distribution.

Municipal fiscal relationship

The most direct fiscal relationship with electricity distribution rests at the municipal level in two key ways. First is the annual dividend spun off from profits of LDCs and the second is the equity value of LDCs.

The municipal dividend

Other than distribution assets owned by Hydro One across mostly rural areas of Ontario, municipal governments receive the vast majority of the net income from LDCs. As discussed in further detail below, a municipal government can choose how much of their LDC's income to take as an annual dividend which goes into general revenue, or forgo that direct revenue and in favour of an increase in the equity value of its business enterprise.

These values can be quite significant. Ontario municipal governments are required to complete an annual Financial Information Return, collected by the Ontario Ministry of Municipal Affairs and

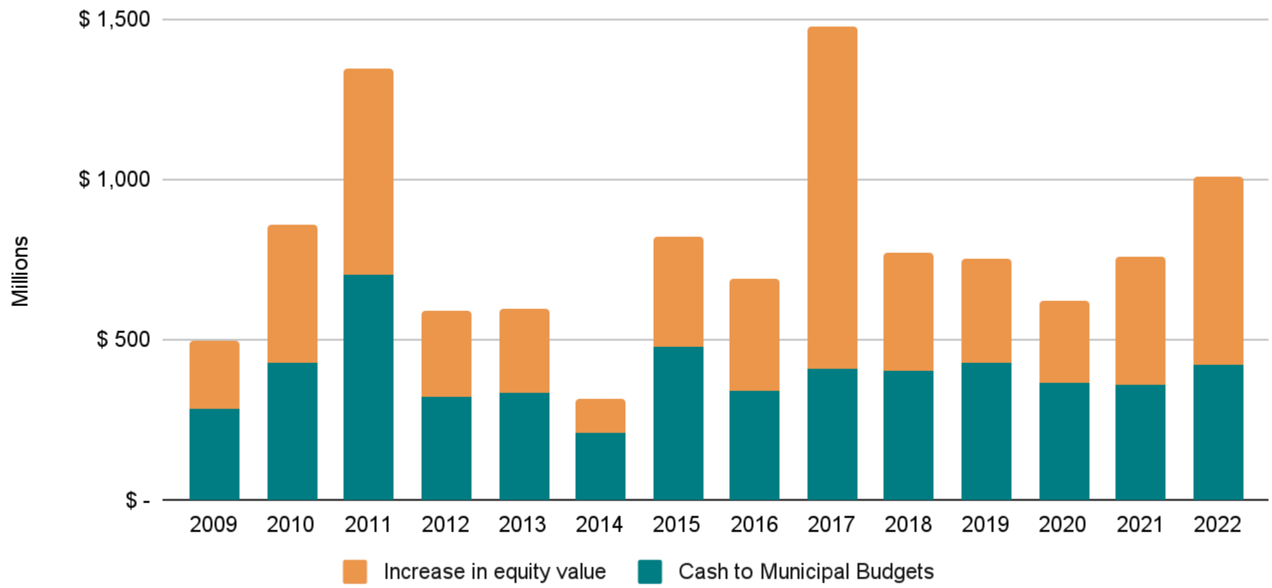
Housing.[9] These reports require cities to compile the total equity increase and dividends brought into annual revenue from all their government business enterprises. Electricity distribution companies are by far the largest source of municipal government business enterprise income and equity increases. In many cities, for example Whitby and Mississauga, their ownership stake in electricity distribution is the only municipal corporation they report dividends from. In others, such as Toronto, the $93 million in dividends paid to the city in 2020 were over 90% of total government business enterprise dividends reported. In 2019, Toronto's $100 million dividend from Toronto Hydro was 56% of total government business enterprise dividends.[10]

Total government business enterprise revenues in Ontario municipalities has been about $400 million per year since 2015 (see Figure 3). This represents about 1.5 to 2% of the total property tax revenues of Ontario cities, which is the main revenue source that cities would have the discretion to increase to replace dividends. LDC revenues do not represent an existential amount of money for cities. However, these dividends are coveted by municipal governments because they come at little political expense. They are not a tax, or a user fee that must cover only the cost of a service, and there are no conditions attached to them, unlike provincial transfers.

[9] These reports are largely standardized, though there is some variation in how dividends are reported. We have tried to correct for this, but our estimates are likely an underestimate of total dividends.

[10] The Financial Information Return also has a schedule in which municipal governments report their incomes from their government business enterprises (schedule 76). This schedule provides some information on the various kinds of government enterprises, however the reporting is very inconsistent. For example, most cities ceased reporting the details of their government business enterprise revenue sources after 2020.

Figure 3: Municipal annual revenue, dividend, and increased equity value of government business enterprises



Source: Line 1865 of schedule 10 of Ontario Ministry of Municipal Affairs and Housing Financial Information Return for cash to municipal dividends. For Barrie, Mississauga, and Markham, we use line 6060 and 6065. Equity value increase is line 6020 of schedule 10.

Political incentives for municipal ownership

The LDC's board of directors decide on the dividend paid to shareholders. Municipal councillors hold a large share of the board seats on LDCs. As this dividend has become an important part of municipal budgets, it has affected the decision making of LDC boards to reflect the desire of shareholders. Fremeth and Holburn (2020) conducted a survey of LDC board members, including municipal and non-municipal shareholders. They found that municipal councillors have the strongest desire among board members to prioritize the dividend over re-investment in the LDC. This is not surprising, as municipal representatives likely have short-term priorities of reducing property taxes, representing their community's interests over the interests of the LDC as a whole, or using dividends for other municipal priorities, rather than focusing on the long-term growth of their LDC, even though as directors their fiduciary responsibility is to the LDC.

Board governance is particularly difficult to measure for municipal LDCs because they are not publicly traded corporations, which have higher standards on disclosure. Financial performance cannot be gauged by metrics such as stock market performance. Many LDCs fail international tests of corporate governance transparency, suggesting a need for reform (Holburn and Regnault 2024).

The municipal equity value

When municipalities elect not to collect the dividend from government business enterprises, they still earn the value of the net income through owning a more valuable asset. The value of Ontario government business enterprises has increased significantly since these assets were put on municipal balance sheets in 2009. They have collectively increased in value from around $5 billion to about $9.5 billion. The largest annual increase occurred in 2017, the year in which a number of municipal governments merged their electricity utilities to create Alectra. These cities saw outsized increases in their equity value of government business enterprises.

These equity valuations on municipal balance sheets are likely dramatic underestimates of the true market value of LDCs. Robins (2017) estimates that the total fair-market equity value of all Ontario municipality-owned LDCs in 2015 ranged from $10.7 billion to over $15 billion. Why this dramatic difference in municipal own-valuation versus potential market value? The market value reflects the premium that private investors are willing to pay for assets with the earnings and risk profile of LDCs. These are attractive assets for investors looking for steady and long-term earnings, which are difficult to come by. Investors do not have the same kind of alternative revenue sources that councils do. Councils' ability to set taxes give governments certainty, albeit at a political cost, about future revenues. Therefore, assets like electricity distribution that have highly predictable revenue streams have a higher value to investors than they do to a government as a business enterprise.

Municipal governments also fall into a fallacy of discounting future revenues from government business enterprises at their cost of borrowing, not on the discount rate that would be appropriate for investment in the government business enterprise itself. A municipal government faces low borrowing costs because it has the nearly unlimited power to increase taxes to ensure debt holders are paid. LDCs, however, face regulatory limits and definitions of the return on investment and make investments that face execution risk. As Robins (2017) shows, this fallacy leads cities to underestimate by more than one-third the true equity value of their LDC investments.

Provincial and federal fiscal relationship

The Province of Ontario and Canadian federal government both have direct and indirect fiscal relationships with LDCs. The primary issue is that the province would collect significant transaction taxes if a municipal government sold more than a 10% equity stake to a non-municipal entity. The province has used the income it receives from local distribution assets to help service debt from over-budget nuclear expansion decades ago. In order to ensure this revenue is steady over time, it also applied large transaction taxes to any sale of LDCs. The federal government also imposes a similar tax, which in fact would go to provincial coffers in the instance of a municipal LDC becoming taxable. These taxes have prevented sales of LDCs to private actors and thus the province is now reviewing what to do with these taxes going forward.

Provincial fiscal role

The provincial government's main fiscal benefit from the LDC sector comes from its ownership stake in Hydro One. In addition to receiving dividends from the transmission arm of the corporation, which is out of the scope of this report, it receives its share of the dividend from the distribution arm of Hydro One. Hydro One Networks, the distribution arm of Hydro One, has made net income of around $400 million per year since 2019. The dividend payout ratio as a whole for Hydro One was about two-thirds and the province owns about 50% of Hydro One, suggesting that annual provincial dividends from Hydro One's LDC operation are around $130 to $140 million per year. Ontario also benefits from increases in equity value as Hydro One's market value increases, but the province only realizes such benefits if it monetizes its stake.

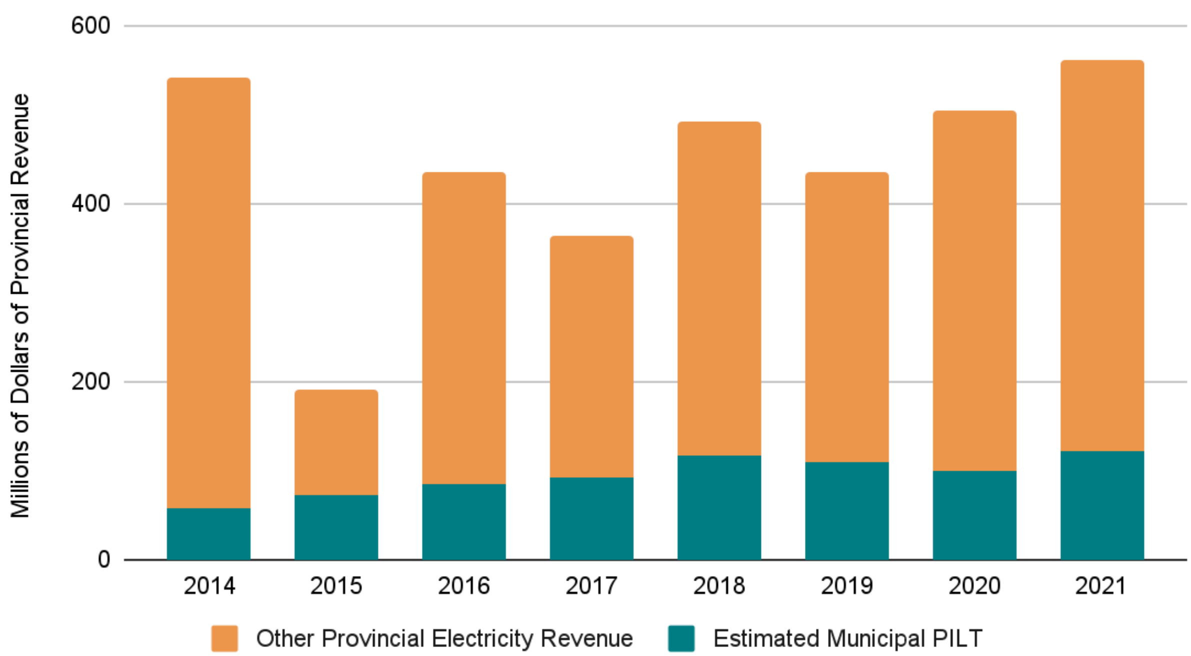
A second fiscal relationship the province has with municipally-owned LDCs is a payment in lieu of taxes (PILT). Because they are municipally owned (defined as 90% of shares held by municipalities or their subsidiary corporations), they are not subject to regular federal or provincial corporate income tax.[11] The province created this PILT system in the late 1990s when it also required municipal governments to set up LDCs to operate local utilities. This reform happened at the same time as the dissolution of Ontario Hydro into component parts, such as Hydro One and Ontario Power Generation. The PILT collects for the province the equivalent value of both the provincial and federal corporate income taxes at the prevailing rates, which is around 25% of net income. The PILT was needed to create a level playing field between privately- and publicly-owned electricity companies.

As the province was considering encouraging private investment in these component parts at the time, Ontario taxpayers took on the large debt and liabilities ($38 billion) accumulated in part through the over-budget construction of nuclear power plants. This debt would have been impossible for a private buyer to take on. This made it a stranded debt. The province created the Ontario Electricity Financial Corporation (OEFC) as the legal continuation of Ontario Hydro and holder of this debt. The OEFC began to pay off this stranded debt based on the flows of profits from provincially owned electricity companies and the PILT the province collects from municipal LDCs. As of 1999, the stranded debt was $21 billion higher than the future flows of these incomes and the underlying assets the province owned, resulting in a residual stranded debt. The province collected an additional debt retirement charge from consumers through to 2018 that reduced the debt considerably.

[11] In Ontario, because of the shared administration of the corporate income tax, the federal government income tax rules prevail.

Over nearly 25 years, these policies have worked to bring total debt levels down to the value of assets the province owns in the sector. The result is that there is no longer a residual stranded debt. The province has collected a steady stream of electricity sector revenues, with PILT now representing a component of about $550 million worth of provincial electricity sector revenue as of 2021 (see Figure 4).[12] It collected a large one-time revenue boost as a tax charge on the partial sale of Hydro One. However, this tax charge was reflected in the valuation of the province's stake in Hydro One in 2016, therefore having no net fiscal effect.[13] The province does not break out the components of its revenue from municipal PILT or other amounts. We estimate what municipal PILT would be, based on an assumption that PILT would be 25% of LDC net income. This results in approximately $100 to $120 million in annual municipal LDC PILT revenue to the province.

Figure 4: Estimate municipal PILT and other provincial electricity revenue (excluding Hydro One sale taxes)



Source: Calculations from OEFC and OEB data.

[12] This is over $700 million as of the 2023 fiscal year. We do not show the most recent amounts as the LDC income data we use to calculate the municipal component is not available for that year.
[13] Since this initial transaction, the final incidence of these tax bills has been disputed in courts. The initial ruling from the OEB was that shareholders would be responsible for bearing the cost of this tax. However, recent court rulings have enabled Hydro One to collect certain tax recoveries from ratepayers.

The province put in place safeguards in its tax system to ensure that it would receive the PILT revenue to pay off the OEFC debt in case an LDC left the PILT regime and became a normally taxable corporation. It introduced a transfer tax initially at 33% of gross proceeds, reduced in 2015 for a time-limited basis to 22% for large LDCs, and eliminated entirely for LDCs smaller than 30,000 customers. This transfer tax had the aim of prepaying to the province the PILT it would forgo. However, this tax of over 20% is such a significant barrier to a potential sale that no parties to a transaction are likely willing to pay it. There were exemptions for public-to-public transfers, creating an unlevel playing field that excluded private investment. Furthermore, the original assets that cities received, without also bearing the debts the province incurred to construct them, now have likely been replaced.

Since the original reduction of the transfer tax in 2015, the province has extended this time-limited reduction repeatedly. However, there have been no material changes to the ownership of municipal LDCs under this new regime and little to no transfer tax paid. In March 2024, the province announced a more significant review of this transfer tax regime, with details of the next steps for the sector to be announced in the 2024 Fall Economic Statement.

Federal fiscal role

The provincial PILT regime operates in the context of federal tax policy. Federal tax rules define whether a certain ownership structure makes it exempt from normal corporate income tax. The current tax rules specify that a corporation with 90% municipal ownership is tax exempt, therefore allowing the province to introduce its PILT. Therefore, the federal government currently collects no income tax from Ontario municipal LDCs, with the province collecting the equivalent of the federal share.

However, the provincial government would have a potential revenue collection opportunity if a municipal LDC no longer was tax exempt. Upon a sale that trips over the 10% non-municipal ownership share, the provincial government would collect a departure tax. This departure tax would be the same amount regardless of whether it was a partial or whole sale. The departure tax mimics a capital gains tax, or recapture of depreciation, and reflects what the LDC would have owed the province in tax had the entity been taxable the whole time of its existence. The parties are able to deduct the departure tax they would owe the provincial government from transfer taxes they would also pay the province.

This departure tax is a federally defined rule the province operates within. It is meant to reflect a realization of capital gains that have otherwise gone unpaid or the recapture of capital cost allowances up until the date of the company's changing from the PILT regime to the corporate income tax system. The system also works in reverse. If, for example, a municipality bought a taxpaying corporation, the federal government would collect the capital gains it would be owed upon the sale of the asset. This is akin to how Canadian taxpayers pay capital gains on the increase in value of their assets upon death or declaring they are no longer Canadian taxpayers. The key difference is that the LDC under the new tax rules has not died or moved to another country, but is instead reconstituted with the same assets. The unique feature in the current context of municipal LDCs is that the province of Ontario is the fiscal beneficiary of this federal tax rule.

Electrification necessitates electricity distribution reform

Key takeaways

- Ontario electricity distribution companies have historically seen capital expenditures grow directly in line with peak electricity demand. If peak electricity demand grows in line with forecasts from the IESO, capital expenditures will more than double today's total within decades.
- Electricity companies are constrained in their choices on how to finance this. Limits on debt growth, returns on equity, and expectations from municipal governments on dividends will result in a financing gap to meet investment needs.
- We estimate this financing gap at $4.7 billion in the baseline model between 2025 and 2040, given current regulatory and municipal practice, with various other outcomes of a financing gap between $2.2 and $8 billion.
- LDCs and their municipal owners will need to consider various options to fill that gap, ranging from taxpayer support, costs on homebuilders, higher rates, or non-municipal investors.
- We show that changing policies such as the after-tax rate of return, altering assumptions about the growth in peak electricity demand, or changing allowed debt-equity ratios all result in lowering or increasing the financing gap.

The above factors of electricity demand growth, regulatory protection of affordability, and government revenue needs are now colliding.

The coming electricity distribution financing crunch

We will show how forecast investment to satisfy peak electricity demand in a net-zero Ontario, core regulatory principles, and short-term government fiscal needs will be incompatible given current practice.

Forecast investment growth

The first key assumption in assessing the future of Ontario's electricity distribution sector is determining the driver of investment. As per the Electricity Distributors Association (2024) report, we assume a linear increase in the growth of gross capital investment along with the growth of peak winter load. These increases in investment will then be reflected in capital investment decisions that LDCs will seek OEB approval on. Once approved, this capital investment will result in an increase in the asset value of LDCs. This is the rate base of the LDC, which the OEB reports as part of its annual release of LDC data. To model the potential growth needed to meet a net-zero Ontario economy by 2050, we take this rate base from 2016 to 2022, then assume that the rate base grows according to the IESO's modelling scenario of winter peak demand through to 2040 in its 2022 Pathways to Decarbonization report.[14] A further uncertainty in capital planning beyond the scope of the model presented here is the effect of climate change itself on investment needs, such as damage causing early write-downs, which is likely to exacerbate capital investment presented here. We also assume that LDCs anticipate rate base growth by three years in their capital financing, allowing for some lag time between when LDCs begin construction and when they must meet growing peak demand.[15]

Regulatory constraints

A fundamental premise of corporate financial planning is that a corporation's assets should match its liabilities. Assets over and above the value of debts and other obligations are the net equity of the firm's owners. As discussed above, the OEB assumes that LDCs have a capital mix that is no more than 60% debt. This ratio allows us to forecast what the relative mix of equity and debt finance will be as we forecast the growth of distribution assets. We also assume that the regulated rate of return on equity stays at 9%, but that after tax (which would represent the PILTs or a combined federal and corporate income tax of 25% of income) brings a post-tax operating cash flow of 7% of equity investment.

Dividends versus equity reinvestment

Once the LDC earns a profit, it then has a choice about what to do with that profit. It can pay dividends to equity shareholders, or reinvest the profits into the corporation. Each corporation can choose its own dividend policy, which it does in consideration of the view of its shareholder(s). For example, Hydro Ottawa has a resolution with its shareholder, the City of Ottawa, to return the greater of 60% of profits or $20 million each year, provided the corporation

[14] Peak demand between 2022 and 2023 grew by 4%, albeit summer-to-summer. We use IESO decarbonization pathway forecasts of peak winter demand for growth forecasts beyond that.
[15] We use changes in the net rate base, not gross capital additions, to estimate the financing gap. The difference between these two figures is the depreciation of the system. Ratepayers are contributing to utility financing of depreciation by about $1 billion per year. Because revenues to cover the depreciation component of annual expenses add to available financing, we ignore the need to cover depreciation costs.

meets regulatory and other requirements.[16] Until 2023, Toronto had a similar shareholder directive of 60% of profits returned as dividends. Elexicon, serving the eastern GTA, has an agreement specifying a 52.5% dividend payout, subject to similar requirements.[17] Hydro One has provided dividends per share, about half of which are owned by the Province of Ontario, of about 64% of profits the last three years.[18]

The corporation's choice of how to direct profits, between dividends and re-investment, is constrained by its capital investment plan. If the corporation wishes to grow its assets, it uses a mix of new debt financing but also reinvestment of profits. It must choose a mix of debt and equity reinvestment to ensure it stays within regulated boundaries of debt-equity ratios. Thus, how much profit to distribute to shareholders versus reinvestment comes full circle on the corporate finance chain to the asset growth forecast. If the asset base is to grow, a corporation must provide sufficient equity capital to match its growth of debt.

Implications of decarbonization for electricity distribution finances

We take these core principles to estimate what the financing of Ontario LDCs has looked like in recent years and the outlook for future investment needs in a net-zero Ontario. We calculate the total increase in the rate base, or total annual investment. We use actual growth between 2016 and 2022, and estimate the capital investment required from 2023 onwards.

Figure 5 shows these historical and projected capital investment requirements for Ontario LDCs annually to 2040, including the annual capital investment shortfalls facing the LDCs. The total shortfall between 2025 and 2040 is $4.7 billion.

The assumptions underlying this projection are that LDCs have a 60% dividend payout ratio,[19] earn a 9% return on equity, and have a 60-40 debt-equity ratio. We also assume that the asset base grows in line with the IESO forecast of peak winter demand in its decarbonization pathway. Under these assumptions, $8 billion in equity reinvestment is sustainable to 2040, as reflected in Figure 5. However, the total equity investment needed is about $13 billion, resulting in a financing shortfall.

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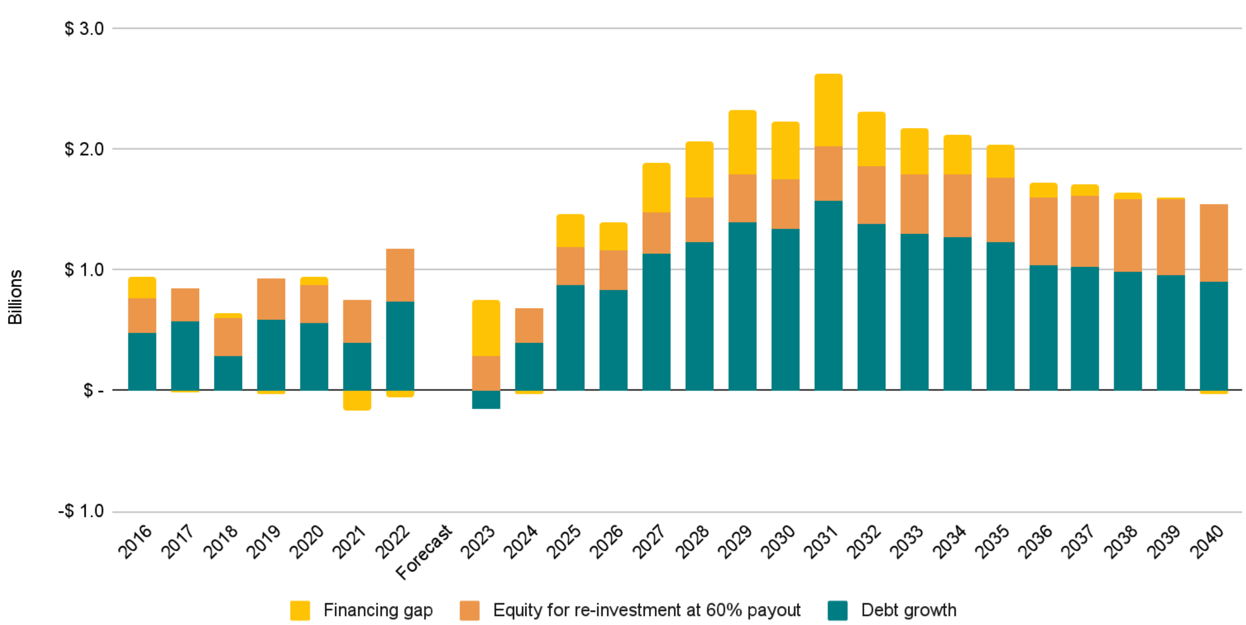
[16] See note 18b of its 2022 financial statements.
[17] However, it was unable to meet that target in 2022. See note 17 of its 2022 financial statements. And in 2023, Elexicon made almost no net income, and paid a smaller dividend in 2023 than 2022, but more than the 52.5% of profits target. See its 2023 financial statements.
[18] See Hydro One's 2023 financial statements.
[19] We believe this is a middle ground of actual historic payout ratios to shareholders representative of Hydro Ottawa and Toronto Hydro. Elexicon has a lower specified ratio, while Alectra and Hydro One have had higher ratios.

The results applied backwards to actual LDC income and asset growth from 2016 to 2022 are in line with the actual results (below in Figure 5) of a modest shortfall of equity financing being supplemented by increased debt. Shareholders could have taken around 60% of profits as dividends and not threatened long-term growth by taking on incremental amounts of debt.

Our model predicts a shortfall for capital financing in 2023, which appears to be borne out by recent events, such as Elexicon not meeting dividend expectations and Toronto Hydro receiving a large capital infusion in 2024. This is just the beginning of increased capital financing needs. Starting in 2028, the IESO forecasts that winter peak demands will increase investment needs sharply. The resulting shortfall in capital financing is $4.7 billion over 15 years starting in 2025, given the stated assumptions about growth: a three-year lag between capital financing and when the increase in capacity that investment produces is used, maintaining dividends, and regulatory requirements. The annual financing gaps reach highs of $500 million in the early 2030s. Furthermore, the results in Figure 5 are a provincial average. Some LDCs are likely to see even greater investment needs and face more acute financing shortages. In addition, the assumed growth in debt follows the maximum allowed by regulators. The model implies a tripling of annual debt issuance between recent levels and total debt financing needs by 2034. This would be a large increase in the amount of debt. It is unclear whether there will be enough demand for this debt. If there are not enough buyers, more equity would need to fill the financing gap.

Figure 5: LDC financing sources and gap, actual and forecast, 2016-2040



Source: Author’s calculations from OEB open data and IESO.

Implications of other assumptions

The model in Figure 5 shows one potential set of outcomes. Changing the model's parameters changes the total financing gap, and has other consequences as well. Table 3 (below) presents the change in the financing gap between 2025 and 2040 under the following scenarios:[20]

1. **The OEB allows for a greater share of debt financing, moving LDCs' deemed debt-equity ratio to 65-35.** This change would allow LDCs to increase the amount of debt they use to finance growth. Greater reliance on debt reduces the equity reinvestment required. As a result the financing gap falls to $4.1 billion. The consequence of this change would be greater financial risk in the LDC sector, and potential credit-rating downgrades that could lead to higher borrowing costs, thereby undermining the original rationale of taking on more debt to finance growth.

2. **Electricity demand growth is slightly lower than the IESO forecast.** Reducing annual growth of electricity sector peak demand by one percentage point (e.g. annual growth in peak capacity from 2033 to 2034 is 6.1%, rather than 7.1%) reduces the financing gap to $2.2 billion. This may result from, for example, economizing on investments needed to meet peak capacity, or total peak capacity need growing slower than the IESO forecast. In this scenario, the 2040 rate base is 78% larger than in 2024 (compared to 100% larger in the baseline scenario shown in Figure 5).

3. **Annual growth in the hourly demand peak is one percentage point higher than the IESO forecast.** This may result from a faster deployment of electricity-intensive demand. In this scenario, where growth of the rate base is one percentage point higher than the IESO forecast, the total financing gap is $8.0 billion. In this scenario, the rate base is 140% larger in 2040 than in 2025.

4. **The timing of electricity demand growth is different than in the IESO's forecast.** In this example, annual growth in hourly peak demand is one percentage point lower than the IESO forecast in its forecast period of peak growth from 2025 to 2035, but one percentage point higher between 2035 and 2045. As in the baseline scenario shown in Figure 5, this scenario grows the rate base by about 100% between 2025 and 2040, and slightly increases the total financing gap to $5.2 billion.

5. **LDCs are able to increase their after-tax rate of return on equity to 9%.** Current OEB regulation targets a 9% pre-tax return on LDC equity; the after-tax rate of return is closer

[20] Each row in Table 3 is the result of changing one parameter from the baseline model. These estimates also include periods in which profits in the late 2030s result in a negative financing gap, resulting in more profitability of LDCs than is needed to meet other restrictions.

to 7%. A combination of the OEB allowing a greater rate of return and/or reductions in the annual income taxes these companies pay (for example, through an investment tax credit) would result in greater profitability and therefore greater equity available for reinvestment. This scenario reduces the financing gap to $2.6 billion. The consequence of this change, however, could include reduced affordability for electricity consumers, higher taxes, reduced government services, or increased government debt due to lower corporate income tax revenues.

Table 3: Sensitivity analysis of changes to financing gap

Baseline and alternative scenarios	**Total equity financing gap, 2025-2040**
Baseline scenario (current OEB regulation and IESO forecast)	$4.7 billion
1. LDCs allowed a higher debt-equity ratio (65/35)	$4.1 billion
2. Annual growth electricity demand is one percentage point **lower** than the IESO forecast.	$2.2 billion
3. Annual growth in electricity demand is one percentage point **higher** than the IESO forecast.	$8.0 billion
4. Lower initial growth in electricity demand compared to the IESO forecast, higher later growth	$5.2 billion
5. LDCs increase after-tax rate of return to 9%	$2.6 billion

Options to fill the financing gap

Governments, both municipal and the province, are by far the largest equity owners of Ontario's electricity distribution sector. Under the current ownership structure, government owners will either need to forego earning a dividend or find equity financing via other means. Some potential options include seeking financing from ratepayers, homeowners, other governments, or opening equity ownership to investors willing to take a lower, longer-term dividend for the prospect of longer-term and steadier growth of future profits. Each option has tradeoffs.

Ratepayers

Ratepayers are the optimal final payer for electricity. However, the capital investment to be able to deliver electricity in any given minute takes years of previous capital outlay. The fundamental question becomes the time frame over which ratepayers should finance the expense of delivering that electricity. To have current ratepayers finance these investments would require higher rates today to benefit future ratepayers.

Electricity prices are politically sensitive and increasing them at a higher rate than the provincial government's two percent annual cap may not be politically feasible. Over $7 billion per year is transferred from Ontario taxpayers to ratepayers to limit increases in electricity rate growth. To protect taxpayers, these subsidies should fall. But to reconcile electricity affordability goals with fiscal restraint, per-unit system costs in the electricity sector must also fall. This $7 billion taxpayer support is largely to offset the costs of investment in electricity generation. Adding further burdens to ratepayers or taxpayers in order to invest in electricity distribution would only make matters worse.

Homebuyers

LDCs have the ability to finance expansions of electricity infrastructure through developer contributions (see discussion in Box 2 above). The costs are initially borne by housing developers, but they likely pass these costs onto homebuyers. These costs could be either borne directly through higher direct housing costs, or indirectly, if developers choose not to build, which limits the availability of housing and drives up prices.

The OEB has various options to replace the current system, each with its own limitations. A proposal for LDCs to levy development charges, in which developers do not get any kind of deposit back, is akin to the current model of how municipalities finance their own infrastructure, and would place the full capital expansion cost on all new homes. Indeed, such a system did operate in the past, referred to as an "upstream charge". However, this would increase new housing costs. Another option takes the opposite approach and would remove upfront costs on homebuilders and spread the capital costs of new expansions across the rate base of the entire LDC, as the natural gas system currently does. Unless LDCs pre-finance that growth from existing customers, that raises questions of where the LDC would find the finance for new upfront investment for future customer revenues and the political consequences of existing ratepayers bearing the cost of new development.

Government or infrastructure bank financing

Government financial support for service provision is most easily justified when there is a broad social benefit, concerns about equity or ability to pay, or when it is difficult to directly bill the beneficiaries and limit the benefit to those who pay. One element of the case for government support is the social harm of emissions offset by non-emitting electricity. Canadian governments have largely steered away from directly supporting electricity distribution companies. Indeed, recent federal legislation for investment tax credits only included electricity generation and transmission facilities, not local distribution. Ontario does subsidize bills, with total fiscal costs reaching over $7 billion annually. The primary justification for this, however, is that previous investments in generation technologies with decades of benefit have been borne predominantly by this generation of ratepayers.

However, such direct financing comes at a cost. If municipal and provincial governments, as owners of LDCs, provide equity financing they face the political risk of pitting long-term decarbonization investment against other priorities. That will pit the investment needs for housing and the energy transition up against schools or hospitals at the provincial level, or libraries and roads at the municipal level. Voters, and therefore politicians, are likely to choose the tangible services they see and benefit from now, compared to long-term infrastructure investments.

Another option that provides government financing, but no direct political involvement, is funding from the federal Canada Infrastructure Bank, or Ontario's Building Ontario Fund (previously known as the Ontario Infrastructure Bank). These banks provide loans or equity investments in infrastructure, like electricity distribution systems. However, the mandates of these banks are to provide funding that leverages additional private sector investment, either in the initial investment or in subsequent rounds. For example, the Canada Infrastructure Bank offers an Infrastructure for Housing Initiative that provides reduced-rate loans to cities and municipally-owned corporations when supplemented by private capital (Fenn 2024).

Pension funds or other infrastructure and energy system operators

Private sector equity investment in LDCs could come from multiple sources. Canadian pension funds are a potential source of equity finance. OMERS, for example, has a 4% stake in Alectra. Canadian pension funds are being actively courted by Canadian governments to increase their investment in domestic infrastructure. For example, the 2024 federal budget created a working group, led by former Bank of Canada Governor Stephen Poloz, to identify potential investment opportunities.

Pension funds have a unique characteristic among investors in that they are not taxable entities themselves, akin to municipally-owned LDCs. Their tax-exempt status puts them at a competitive advantage relative to other taxable corporations. This advantage is one of the reasons for federal limits that restrict pension funds from owning more than 30% of a corporation. Pension funds can't own more than 10% of municipal LDCs without triggering departure and transfer taxes.

Equity investment could also come from operators of other kinds of infrastructure or energy systems. One key rationale for including other energy system operators is that they can bring significant operating expertise. Equity owners with experience building large distribution networks and predicting future operating costs, or experience with novel technology, can enhance the value for municipal co-owners (Fenn 2024). Partners that bring these kinds of expertise can offer more value than simply surrendering future dividends via an equity stake that provides upfront money to government owners. However, like pension funds, these investors are currently prohibited from owning more than 10% without triggering departure and transfer taxes. Key considerations include the structure and size of the investment, risk tolerance, and other regulatory barriers; these are beyond the scope of this report.

Fundamental change to the utility model

Decreasing the rate of growth in centralized generation demand can reduce the distribution system investment needs, and therefore reduce the financing gap. This is a rationale for moving to a distributed system operator model. Although this would likely require less direct infrastructure capital than a traditional local utility, a distributed system would have a fundamentally different business and risk profile than the current centralized model. A full assessment of the investment needs associated with moving to a distributed system operator is out of the scope of this report. Such a fundamental change in the operations of local grids would raise questions about the ideal financing mix, workforce skills, and governing policies to best enable the transformation.

Reformed pricing models may reduce peak capacity usage and therefore the investment needed to satisfy peaks, but are also beyond the scope of this report.

Reforms needed

Key takeaways

- To create the conditions for non-municipal investments in electricity distribution to be economical, the provincial government should reduce or eliminate its transfer tax, and rebate departure taxes.
- The fiscal cost to the province of reducing the tax burden would be minimal and less than the long-term financing gap that Ontario LDCs face.
- Removing these transaction taxes gives municipal governments additional choices for how to fill LDC financing gaps.
- Regulatory protection is a key part of any reforms. The OEB should strictly enforce public interest protection under any kind of LDC ownership.

If Ontario's electricity distribution sector is to contribute to a net-zero economy, the system must change in some capacity. This will include changes to federal and provincial tax policy, municipal ownership decisions, and provincial regulatory policy.

Tax changes to enable non-municipal LDC investment

Non-municipal equity investment is key to filling the equity financing hole that Ontario LDCs face. However, for non-municipal equity financing to be economically viable, both the federal and provincial government should consider changing tax rules that are no longer fit for purpose.

Transfer tax changes

The provincial transfer tax has outlived its original purpose. The PILT regime worked successfully to pay off the residual stranded debt that Ontario Hydro accumulated through to the 1990s. It is therefore time to eliminate the transfer tax, which acted as a backstop to ensure the paying off of this now-eliminated residual stranded debt.

Departure tax changes

The province also collects a departure tax in the event that non-municipal ownership of an LDC exceeds 10%, and the LDC becomes subject to corporate income taxes. Retaining the departure tax creates an unlevel playing field, as companies such as EPCOR, owned by the City of Edmonton, would remain exempt from the departure tax in any purchase of an Ontario LDC.

Indeed, Hydro One's acquisitions of LDCs before its partial sale were exempt from transaction taxes, giving it a substantial advantage over other private utilities in consolidating LDCs that sought to merge or be bought out.[21] However, this departure tax may create barriers to private investment. There are two approaches that governments are likely to consider: full elimination of the departure tax or an increase in the threshold of non-municipal ownership that triggers the tax.

Option 1: Full refund of departure tax

One approach for the province is to rebate any departure tax it collects back to the entity that pays, and, to protect affordability for consumers, on the condition that the new entity not recoup the departure tax cost from ratepayers. This change would fully eliminate the departure tax barrier to non-municipal equity investment in LDCs. This option would be neutral with respect to the kind of private investor that eventually purchases equity in the LDCs.

This departure tax change is necessary to facilitate new non-municipal equity investment in LDCs, but wasn't needed for the province's sale of Hydro One. In that circumstance, the province, as the sole shareholder, was fiscally indifferent to paying the departure tax. That is because any departure tax the province paid would be deducted from the sale value it realized, and the tax was payable to the province itself. The same would not be true of cities.

The final incidence of the departure tax cost is highly complex. This was borne out in a series of OEB rulings and court cases related to the financial incidence of tax charges from the sale of Hydro One. Once Hydro One became a regular taxable corporation, it restarted the process of claiming capital cost allowances against its corporate income tax due. However, the value of that capital cost allowance was calculated based on the sale value, which included the departure tax. The initial regulatory hearings deemed that Hydro One's shareholders would bear the tax costs. Subsequent court rulings found that Hydro One could collect a portion of that tax cost from customers, because the province didn't rebate it. As a result, the OEB ruled that Hydro One is now entitled to collect over $250 million of what it paid, plus interest, from Ontario ratepayers. The result is a monthly cost on OEB-regulated customers, with the amount depending on the kind of customer connection. Any decision on departure taxes must grapple with the consequences of this ruling and the long-term financial windfall benefit of tax deductions for depreciation.

[21] Hydro One had an exemption from the transfer tax during the period it was a non-taxable government business enterprise. See section 20 of O. Reg. 124/99.

The Ontario government would have the most to lose from a full elimination of the departure tax. After a sale, the province would lose the federal corporate tax-equivalent component of the PILT and instead only collect the provincial corporate income tax, resulting in about a two-thirds reduction in the total PILT revenue stream presented in Figure 4 (above). However, the equity investment in LDCs that would follow from a tax change would generate greater long-term profits, and therefore increased provincial income tax revenue to offset some of the loss from lower PILTs.

One possibility for resolving this is for the federal government to compensate Ontario with any corporate income tax it receives from LDCs for a certain period of time (see Fyfe et al. 2013 for this proposal, modeled on the former *Public Utilities Income Tax Transfer Act)*. The provincial government should not let agreements to compensate for lost revenue slow the process of tax reform. That is because the potential provincial fiscal cost is likely to be minor. We estimate that the municipal PILT revenues are a very small amount for the province: between $100 and $120 million per year. The province would only forego about two-thirds of that and collect the remainder as regular corporate income tax. It should weigh that small cost against the potential fiscal cost of supporting investment for municipal LDCs that are not willing to consider or able to take advantage of other options (in Table 3 above) to fill a financing gap, nor able to get outside investors. A smart bet for the province to fill the LDC financing gap would be to accept losing two-thirds of its PILT revenue, because it would gain needed investment in municipal LDCs that will benefit Ontarians, help reduce emissions, and bring in additional tax revenue from growing LDCs that are likely to be more profitable in the future once the investments are made.

Option 2: Raising the non-municipal ownership threshold for the departure tax

One option the federal government may consider is retaining the departure tax, but increasing the threshold at which the corporation is considered non-taxable to, say, 49% non-municipal ownership. The current limit of a 10% non-municipal ownership stake for a corporation to be tax-exempt has been a long-standing rule for decades. The 10% threshold is where a corporation's ownership stake becomes that of a beneficial owner.

There are some benefits of increasing the limit for taxable status to 49% non-municipal ownership. This would act to spur investment in municipal LDCs and preserve the province's payment of PILTs. That is, it would have no immediate fiscal cost to the province or the federal government. It would also ensure that voting control of the corporation remains in municipal hands.

However, increasing the threshold of non-municipal ownership and preserving a tax exemption would create a major tax advantage for municipally controlled infrastructure, compared to otherwise similar investments led by private entities. Further, increasing only the threshold for the departure tax would have the effect of creating an additional potential fiscal cost for the federal government. The investments that non-municipal owners make in non-taxable entities may come at the expense of investing in other taxable Canadian investments. Therefore, the federal government would lose the difference in tax revenue between these two investments.

Even more problematic would be for the tax code to define the kinds of owners that would be deemed eligible for the entity to remain tax-exempt, such as pension funds. This would skew the tax code towards favouring certain kinds of investments over others. Furthermore, limiting the kinds of owners that can purchase shares of municipal LDCs will result in otherwise lower sale prices today of LDCs as the buying pool will be smaller. The net losers of that would be current owners of LDCs: municipal taxpayers. In addition, buyers today will know that their potential pool of buyers in the future will be limited by what buyers are allowed to purchase, further depressing their willingness to pay. An even deeper problem is that limiting the buyer pool to pension funds would eliminate one of the core benefits of broader equity investment identified by Fenn (2024), of leveraging the expertise of an operator interested in equity participation.

Action by cities to find non-municipal investors

Once these tax barriers are eliminated, municipal governments will need to choose what to prioritize: affordability of housing, distribution investment to serve the needs of customers, or maintaining municipal equity control.

The immediate pressure municipal governments will face is the preservation of their dividend from municipal LDCs. Municipal governments are likely to lose their dividends if they are the sole equity owners, as shown in Figure 5 (above). There are other options they should consider. Once senior governments have removed the key transaction taxes, municipal owners can structure a potential sale of a portion of their equity stake to maintain or enhance their dividend flow over the period of major equity investment. To preserve that dividend flow, the municipal owners would be trading off potential growth of very-long term dividends, say, beyond 2040, after the bulk of investments are made, to investors with equity investment to deploy now. Equity investors with longer-term investment horizons are likely willing to pay a premium relative to current municipal valuations (Robins 2017). This higher valuation by private investors presents a potential opportunity to construct sale terms that preserve municipal dividends, albeit perhaps at a lower upfront purchase cost.

The other option that municipal governments will have is to receive an immediate investment from equity partners to reinvest in critical municipal infrastructure that must remain under municipal control, such as parks or other municipal priorities. These potential investment amounts are in the billions of dollars and could be deployed to limit municipal reliance on debt. By selling a partial stake in LDCs, not only will existing and future municipal taxpayers benefit, but ratepayers may see benefits too; that is, if private investors follow the cost-savings example of the Hydro One sale in 2015 (Dachis and Balyk 2021).

As Fremeth and Holburn (2020) find, independent directors not associated with a municipal shareholder are more likely to drive investment of retained earnings. More equity owners looking to drive long-term growth for electrification and decarbonization, not just immediate dividends, are likely to appoint directors with a longer-term outlook. Fremeth and Holburn (2020) find that independent directors are likely to be more oriented to growth opportunities, such as those that decarbonization and electrification growth present, than current municipal representatives. Finally, selling partial equity stakes does not mean that municipal governments will lose control over their LDCs. Fremeth and Holburn (2020) suggest that cities can still exert control over LDCs via shareholder agreements which have the benefit of clarifying expectations.

A municipal decision to change the ownership of electricity utilities will be politically difficult. Potential investors will need to make a compelling case to municipal governments to address their potential hesitancies. Options include creating a legacy fund from the sale proceeds that pay dividends over and above any planned dividends from the LDC for a certain period. Other supplements to the sale value are potential local investments or commitments for investment in emissions-reducing technologies. A critical component, however, will be assurance that the regulatory system will protect consumers as well as, or better than, under municipal ownership.

Regulatory protection

The final element of electricity distribution reform is to ensure that the Ontario Energy Board is up to the task of protecting ratepayers, taxpayers, and homebuyers to ensure affordability.

Protecting ratepayers and homebuyers

A core mandate of the OEB is to protect consumers. It does so now with rate applications that come from provincially-owned utilities, municipally-owned utilities, and privately-owned utilities. That mandate will not change if LDC ownership changes.

Regulatory protection is a critical component of assuring public interest protection. In recent years, Thames Water, the United Kingdom's largest water and wastewater services provider, which is owned by a consortium of investors including OMERS, has faced significant scrutiny. The owners of Thames Water underinvested in critical infrastructure. Facing significant investments to meet environmental standards, and after regulatory rejection of increased rates to finance needed investment, the future of Thames Water is uncertain. This is an example of how a lack of regulatory scrutiny can produce long-term risks to consumers.

The Thames Water issues are considered by some an outlier in U.K. water services, as other companies have been able to maintain normal, regulated operations. Electric utility distribution was privatized in the U.K. in the 1990s. Initially, the aim was to increase efficiency and competition, through investments in infrastructure and improvements in service reliability. A regulator (Ofgem) oversees the sector, ensuring that companies meet performance standards while protecting consumer interests. The results overall seem to be a relative success, with distribution network prices growing an average of 3% from 2009 to 2021, although prices spiked considerably in 2022 and 2023 due to the Russian invasion of Ukraine.

Clarity on the mandate of the regulator is critical. A regulator enacts government policy, but does not create it. Clarity from the provincial government about their emissions-reductions goal gives a regulator a clear target to optimize investment plans. If it is clear that the OEB's mandate is to expand electricity distribution to meet net-zero goals, the OEB can execute on policies that, for example, rethink the risk-return framework for investment to seize more potential decarbonization benefits. One social benefit of electricity use comes via the decarbonization benefit. The most efficient way to determine that cost is via pricing systems that put a price on all emissions. However, the provincial government, and the likely future federal government, would seek to remove the price on emissions from home heating sources, which competes with electricity as the primary option for home heating. This could justify direct government intervention in the financing of distribution grids, as a second-best solution to emissions pricing. It also creates a justification for regulators to keep the price of electricity as low as possible, to reduce the environmental harm of using other emitting energy sources.

The OEB also directly oversees the terms of mergers and acquisitions, with a set of guidelines it has updated as recently as July 2024. Private investment that leads to LDC consolidation may lead to opportunities including cost savings for the customers of the smallest LDCs, that would benefit from scale economies (Dachis and Balyk 2021). Private investments could also lead to more efficient OEB regulatory reviews (which every LDC must undergo), if it was conducting fewer of them. The regulatory process should facilitate efficient mergers while also protecting consumers from ill-advised ones (Dachis and Balyk 2021). For example, economies of scale emerged most clearly from the sale of Hydro One, compared to municipal-led mergers.

There are other potential opportunities that could emerge from larger, consolidated LDCs. Large LDCs could become counterparties to generators for electricity sales, akin to the emerging trend of corporate power purchase agreements. Critical to realizing any of these benefits is a regulatory system that ensures that any merger or acquisition is in the best interests of customers. It is equally critical for investors that the OEB has a timely decision-making process.

In addition to ensuring the affordability of electricity for final ratepayers from more private investment, the OEB and the government must tackle how LDCs finance the expansion of the electricity grid. This current system of capital contribution from developers places all of the timing risk of new development and future revenues on home builders, not existing ratepayers or LDCs. There is an additional economic cost of this model. The capital contribution and deposit on the initial expansion of the electricity distribution network is borne by the first entrant or organized group in a new development area. Subsequent developers pay no additional capital costs and free ride on the risk borne by the first developer. This creates a disincentive for the first developer to enter the market, thus slowing down future development as well. This is a generic issue in housing development, in which a lack of service infrastructure has ripple effects, as developers wait for an initial developer to take on a disproportionate share of risk of developing an area (Fenn 2024).

The OEB has commenced a review of this system, at the behest of the previous Ontario Minister of Energy, with a report submitted to the province in June 2024. The province announced in October 2024 that it would implement the recommendations in the OEB report. At a high level, the OEB recommends deferring when LDCs collect revenues from development. This will improve housing affordability. However, deferring capital contributions may have unintended consequences. For example, LDCs may refuse to take on the risk, which homebuilders are currently shouldering, that customers will emerge in expansion areas. Broader equity investment can share this timing mismatch risk (Fenn 2024). For example, developers themselves may wish to make an initial equity investment in the LDCs' expanded infrastructure to ensure the right prioritization to fit their expansion needs. Once complete, the developers could sell their equity stake. These are examples of how different kinds of investment strategies may emerge, based on the different needs of capital investors.

Conclusion and recommendations

Increasing investment in Ontario LDCs from non-municipal sources will involve policy coordination between all three levels of government, and require strong oversight from independent regulators.

Conclusion

Ontario's electrification future depends on investments in the electricity sector. Municipal governments will need to make hard decisions about what they prioritize, between the status quo of municipal control of LDCs, keeping property taxes and electricity rates as low as possible, or investing in our electricity grid to facilitate decarbonization.

The provincial regulator exists to protect ratepayers and homebuyers regardless of who owns LDCs and must consider the effects of its regulation on rate growth and capital structure. The OEB will face a trade-off of tolerating risk and rate growth with financing sustainable growth in local electricity distribution.

Ontario cities and LDCs operate in a tax and regulatory regime defined by provincial and federal governments who must make the first move. It is up to the province to determine if it will create a wide range of opportunities for decarbonization investments through eliminating taxes or loosening regulations that limit investment in Ontario LDCs.

Recommendations

Government of Ontario

1. Commit to decarbonization of home heating and transportation, consistent with the IESO's modelling of a net-zero future, to incentivize investment in electricity distribution infrastructure.

2. Reduce or eliminate the transfer tax that is imposed when non-municipal equity investment in LDCs exceeds a 10% threshold. The transfer tax is impeding LDCs' access to the capital they need to invest in new infrastructure that will meet the growing electricity needs of a net-zero economy. This transfer tax no longer has any policy justification.

3. Consider rebating all or part of the departure tax that is imposed when non-municipal equity investment in LDCs exceeds a 10% threshold. Rebating the departure tax could improve incentives for investment, but may have unintended competitive effects on other LDCs and create windfall gains for certain investors.

4. Ensure that regulatory bodies have robust practices in place to protect consumers and the public interest wherever there is non-municipal equity investment in an LDC. These robust regulatory protections should be applied equally to all LDCs regardless of the ownership type.

5. New homes that can support electrified heating and vehicle charging require big investments in local distribution infrastructure. Work with the OEB to reduce the obligations imposed on property developers to finance new distribution infrastructure. Consider longer-term tools to finance infrastructure growth that balance housing affordability and investment in electricity distribution, such as amortizing distribution assets over a longer time period, as is applied to natural gas infrastructure.

Ontario Energy Board

6. Investment in local electricity grids to facilitate a decarbonized Ontario entails uncertainty about future technology adoption. Uncertainty about the scale of investment needed, and the inherent riskiness of investment plans, is incompatible with the Ontario Energy Board regulatory system. Develop regulatory policies that encourage long-term investment, consistent with a mandate from the provincial government to decarbonize home heating and transportation.

7. Review the terms of any sale of a municipal LDC to ensure consumer and public interest protection. For example, ensure that LDCs are not over-leveraged and placing future consumers at risk. Exert strict discipline on the costs that LDCs propose for rate coverage.

8. Work with the Ontario government to develop long-term tools to finance LDC infrastructure growth, and carefully consider reforms to capital structure rules that inhibit LDC growth, such as adjusting deemed debt-equity ratios to encourage more investment.

Federal government

9. Federal tax rules define a municipal corporation as exempt from federal income tax if it has no more than 10% non-municipal ownership. In addition to a provincial transfer tax, federal tax rules require the province to collect a departure tax once non-municipal investment passes this threshold. Consider the pros and cons of raising the private ownership threshold at which LDCs lose their tax-exempt status. An increase to the threshold can aid in bringing in more investment, but could have unintended long-term consequences.

10. The province collects payments in lieu of corporate income taxes from municipally-owned LDCs to ensure a level tax playing field with private LDCs. Ottawa should consider financial support for the Province of Ontario to compensate it for lost PILT revenues from LDCs that become federally taxable entities.

Municipal governments

11. If senior governments eliminate or reduce taxes that discourage investment in LDCs, consider non-municipal investment partners to facilitate the build-out of electricity distribution, keep electricity costs down, and support municipal taxpayers.

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