Enbridge Gas Compendium for Examination of Chris Neme (EFG)

	Item	Location of Full Document	Pages
1.	Powering Ontario's Growth	Powering Ontario's Growth | ontario.ca	1-6
2.	IESO Reliability Outlook	Reliability Outlook (ieso.ca)	7-15
3.	Powering Ontario's Growth	Powering Ontario's Growth | ontario.ca	16-18
4.	IESO Annual Planning Outlook	Annual Planning Outlook (ieso.ca)	19-23
5.	Powering Ontario's Growth	Powering Ontario's Growth | ontario.ca	24-28
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Powering Ontario's Growth

Ontario's Plan for a Clean Energy Future

ontario.ca/energy

Ontario

Minister's Message

Minister's Message

Over the past five years, our government has worked to make Ontario the best place to create jobs and build the industries of the future. By reducing electricity costs, lowering taxes and cutting red tape, we have significantly reduced the cost of doing business and we've seen companies and investment surge into our province as a result.

Ontario is quickly becoming a leader in building electric vehicles and batteries with historic investments from Stellantis in Windsor to Volkswagen in St. Thomas. And we are working with the steel industry to end coal use and electrify their operations to support the production of green steel in Hamilton and Sault Ste. Marie, fueling our growing automotive sector.

At the same time, our government has a plan to build 1.5 million new homes as Ontario's population is expected to grow by two million people by the end of this decade.

As a result, for the first time since 2005 Ontario's electricity demand is rising, and we know that to support this type of growth we need to ensure the continued availability of reliable, affordable, and clean energy.

Our government is on track to acquire the electricity resources we need this decade to power economic growth and increasing electrification, with major projects and procurements already announced, including Canada's first grid-scale small modular nuclear reactor (SMR), a $342 million expansion of energy efficiency programs and the largest energy storage procurement in Canada's history.

But looking ahead on the path to 2050, we know economic growth and electrification are going to continue to increase energy demand. In fact, Ontario's Independent Electricity System Operator's (IESO) analysis shows that electricity demand could more than double by 2050.

We need to act today to ensure we have the energy we need to power economic growth and electrification over the next three decades while maintaining our clean electricity advantage.

Powering Ontario's Growth is the next chapter in Ontario's clean energy story and lays out the plan to provide families and industries with the reliable, low-cost, and clean power we need to power Ontario's growth.

Generational decisions, like starting pre-development work for a new nuclear station at Bruce, the first large scale nuclear build since 1993, and advancing three additional small modular reactors at Darlington will provide the dependable clean, green, zero-emissions electricity that businesses around the world are looking for.

Connecting Ontario and opening new regions for clean energy generation through strategic new transmission lines and developing long-duration storage, like pumped hydroelectric, will also be pivotal to ensuring our grid is as efficient as possible. While we build the next phase of Ontario's electricity grid to reliably meet peak demand, in the near-term natural gas generation will continue to provide our province with an insurance policy to maintain system reliability and support electrification across our economy.

This growth can only be successful with the participation and leadership from Indigenous communities and partners across the province, whose voices will help ensure energy infrastructure is developed in a way that considers future generations.

With the world-class talent in Ontario's energy sector, I'm confident we will continue to build our clean energy advantage that has made our province so attractive for investment, while providing the reliable and affordable electricity that will keep energy costs down for families.

Sincerely,

Todd Smith
Minister of Energy

Chapter 1

Ontario's Energy System

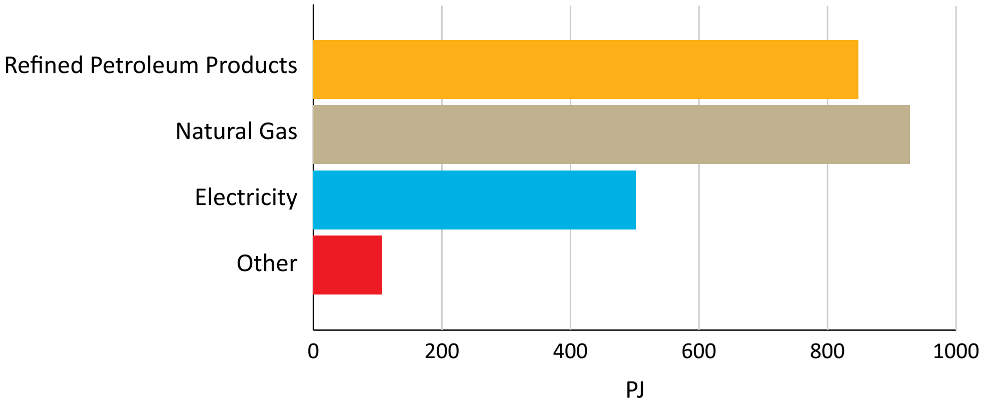
Ontario’s Energy System

1.0 Introduction

Ontario relies on a mix of energy sources to drive its economy, heat, cool and light the homes of its 15 million residents and move people and goods across our vast province.

Electricity, natural gas, and refined petroleum products together account for 96 per cent of the energy Ontario needs with other fuel types such as bio- and industrial-fuels (coal, coke and coke oven gas which are being phased out through the electrification of the steel sector) – accounting for the remaining four per cent.

Figure 1.1: Ontario’s Energy Mix: End Use Demand by Fuel Type

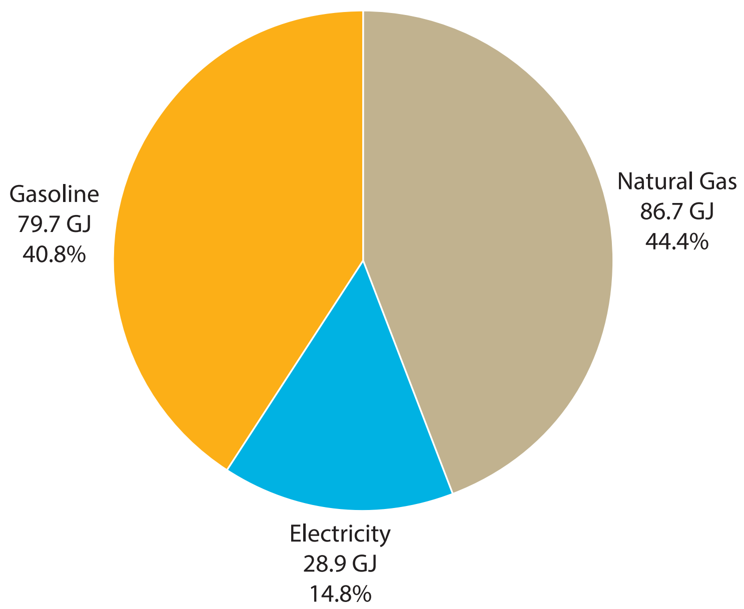


Average household energy consumption is similar to the overall economy with natural gas and gasoline accounting for approximately 44.4 and 40.8 per cent respectively with electricity providing the remaining 14.8 per cent (Figure 1.2). These levels will change as individuals make choices to electrify vehicles and home heating.

Through investment, regulation and innovative public policy, the Ontario government has a leading role in ensuring the province has access to the reliable, affordable supply of energy needed to keep people safe, create jobs and grow the economy.

This chapter describes the role of electricity, oil, refined petroleum products and natural gas in Ontario's energy mix and how they work together to deliver the energy the province needs. It includes an overview of the steps being taken to ensure a reliable supply of electricity and to keep electricity and natural gas costs affordable as needed investments are made to increase generating capacity and meet anticipated demand.

Figure 1.2: Household Energy Consumption (source: Statscan, 2019 data)



Reliability Outlook

An adequacy assessment of Ontario's electricity system

July 2023 to December 2024

ieso
Connecting Today.
Powering Tomorrow.

Executive Summary

Ontario's electricity system is prepared for summer, with adequate supply expected to be available to meet electricity demand and maintain operating reserves. The IESO is prepared for tighter grid conditions that could develop if the province experiences extreme heatwaves – this is similar to last year and is the new norm for many jurisdictions around North America.

Demand for electricity in Ontario is at its highest during the summer months due to air conditioning load. This summer Ontario's electricity system will have multiple nuclear units undergoing refurbishment concurrently, which the IESO has been anticipating and planning for.

Ontario has a diverse supply mix and a variety of tools available to maintain the reliability of the grid. This includes deferring planned generator and transmission maintenance, imports from our neighbours, and consumer demand response.

The IESO's resource adequacy forecasts are intended to provide transparency around current maintenance outage requests and do not reflect final outcomes. Under the current extreme weather forecast, supply is lower than what is required to meet demand and maintain required reserves for 10 weeks this coming summer, reflecting current requests from generators to take maintenance outages. Reserve refers to the amount of supply, plus backup supply, needed to meet North American reliability standards.

If available supply is below requirement, the IESO imports power and/or defers generator maintenance outages to meet the requirement. In addition, the IESO also maintains backup supply to maintain reliability if challenging circumstances arise. Ontario's backup supply is typically equal to the largest generator plus half of the second largest.

The IESO will reject or defer non-essential generator maintenance as system conditions dictate. New requests by market participants for maintenance outages that impact grid reliability will not be approved to proceed during this time if they can be rescheduled.

There is ongoing coordination with nearby jurisdictions as imports will contribute to reliability this summer. Ontario consumers also play an important role in maintaining grid reliability each year. Large consumers participating in the Industrial Conservation Initiative are expected to reduce provincial demand by roughly six per cent. In addition, over 900 MW of consumer demand response secured in the most recent capacity auction can also contribute.

Electricity demand is expected to decline slightly to 136.1 TWh in 2023, a projected reduction of 0.4% from 2022. The impacts of interest rate hikes over the past year are expected to continue over the remainder of the year.

Economic growth is expected to increase electricity demand next year and over the long-term. For 2024, demand is expected to increase to 138.8 TWh, a projected increase of 1.9%. Over

4.2 Capacity Adequacy Assessment

The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages assessed as of May 3, 2023. The generation planned outages occurring during this Outlook period have been assessed as of June 13, 2023.

4.2.1 Firm Scenario with Normal and Extreme Weather

The firm scenario incorporates all capacity that had achieved commercial operation status as of June 13, 2023.

Figure 4-3 shows Reserve Above Requirement (RAR) levels, which represents the difference between available resources and required resources. The required resources equals forecast demand plus the required reserve.

Capacity secured in the December 2022 Capacity Auction (CA) has been included in this assessment. Firm guidance targets for capacity in the December 2023 Capacity Auction, as announced in the IESO's 2022 Annual Acquisition Report, have been included and modelled as demand measures in the firm resource scenario for summer 2024 and winter 2024/25[2].

The IESO expects to have sufficient reserves for the winters of 2023/24 and 2024/25. In the firm scenario under normal weather conditions, available reserves fall below the requirement for six weeks in summer 2023. In the firm scenario under extreme weather conditions, the reserve is lower than the -2,000 MW adequacy threshold for 10 weeks in summer 2023. Under the current outage schedule, the RAR is below the adequacy threshold in the weeks spanning July 9 to September 24, 2023, with the exception of the weeks of September 3 and 17, where it is marginally above the threshold.

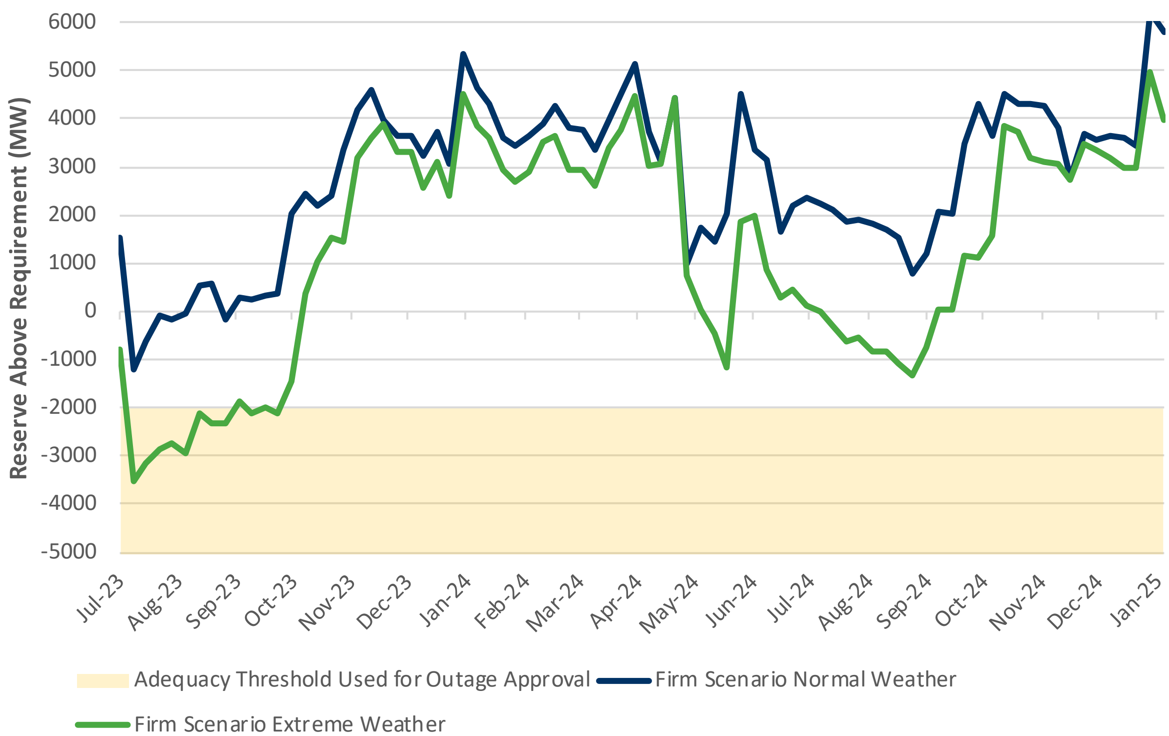
These potential shortfalls are primarily attributed to planned generator outages scheduled during those weeks, including a number of coincident nuclear and gas outages. The IESO is in direct communications with market participants that have planned outages during this period to ensure Ontario maintains adequate reserves. However, should those participants be unable to reschedule certain outages during periods of low reserves, Ontario may have to rely on more than 2,000 MW of supply from other jurisdictions and/or additional operating actions in order to ensure reliability under extreme weather conditions. Likewise, Ontario may have to rely on some imports to meet demand under normal weather conditions.

Outage requests during periods when reserves fall below the adequacy threshold under extreme weather conditions will be put at risk and may be rejected should those conditions materialize. The IESO is in ongoing discussion with generators whose scheduled outages impact the RAR. We will continue to work closely with both these generators and transmitters to ensure outages are appropriately scheduled.

[2] Results of the December 2023 Capacity Auction were not available at the time this assessment was completed. 2022 Capacity Auction results can be found in the post-auction report on the IESO's webpage, and will be included in the firm scenario in future outlooks.

As Ontario continues to experience a period of tight supply conditions, planned generator maintenance outages will become increasingly difficult to schedule during summer. The IESO is prepared to work with Market Participants to reschedule outages to ensure the reliability of the system. Generators are advised not to schedule outages during periods when reserves are forecast to be low, and are strongly encouraged to plan ahead and coordinate the timing of outages with IESO staff.

Figure 4-3 | Comparison of Normal and Extreme Weather: Firm Scenario Reserve Above Requirement

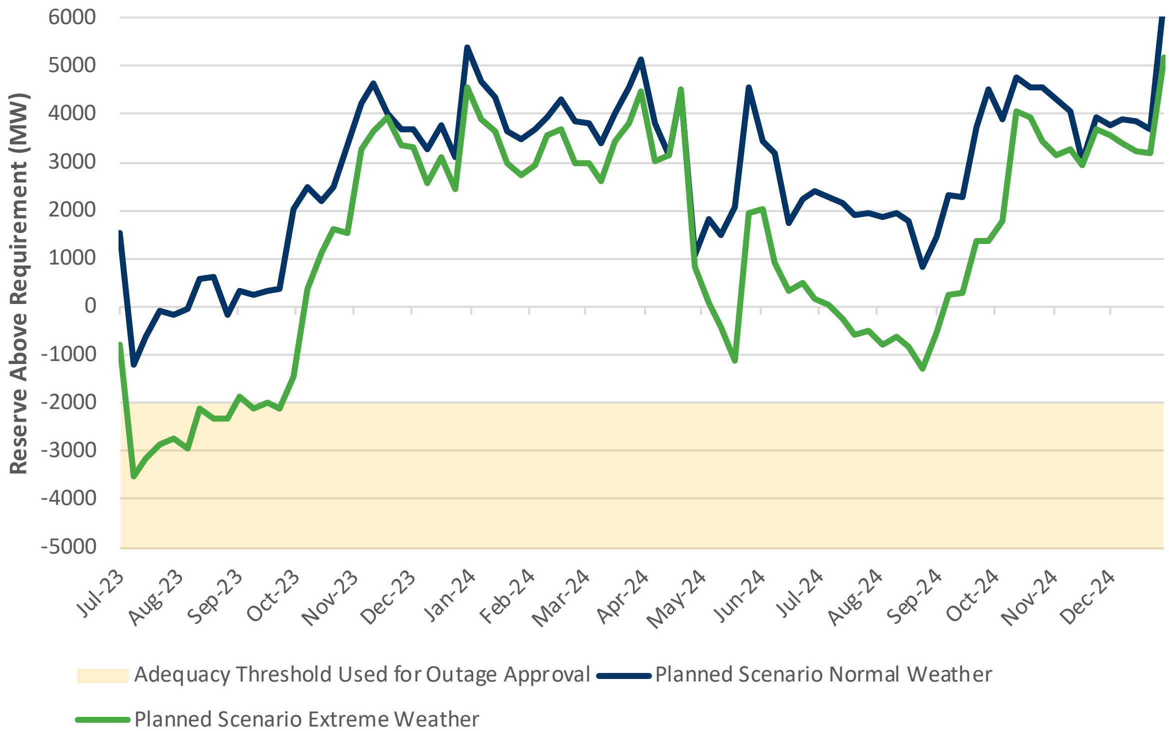


4.2.2 Planned Scenario with Normal and Extreme Weather

The Planned scenario incorporates all existing capacity, as well as all capacity expected to come into service. Approximately 60 MW of new generation capacity is expected to connect to Ontario's grid over this Outlook period.

Figure 4-4 shows RAR levels under the Planned scenario. Reserves fall below requirements for six weeks in 2023 under normal weather conditions. Under the extreme weather scenario, reserves fall short for 10 weeks in the summer of 2023.

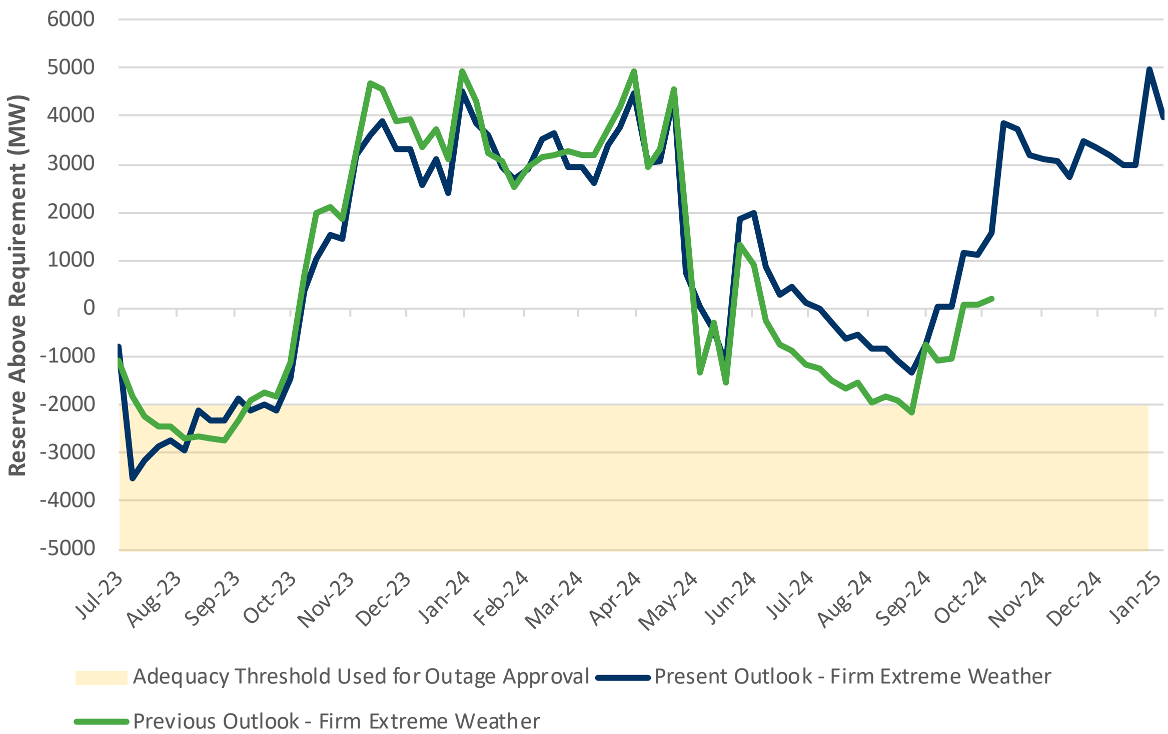
Figure 4-4 | Comparison of Normal and Extreme Weather: Planned Scenario Reserve Above Requirement



4.2.3 Comparison of the Current and Previous Weekly Adequacy Assessments for the Firm Extreme Weather Scenario

Figure 4-5 compares forecast RAR values in the current Outlook with those in the previous Outlook, which was published on March 23, 2023. The difference is primarily the result of changes in planned outages.

Figure 4-5 | Comparison of Current and Previous Outlook: Firm Scenario Extreme Weather Reserve Above Requirement



Resource adequacy assumptions and risks are discussed in detail in the Methodology to Perform the Reliability Outlook.

4.3 Energy Adequacy Assessment

This section assesses energy adequacy to determine whether Ontario has sufficient supply to meet its forecast energy demands, while highlighting potential adequacy concerns during the Outlook time frame. At the same time, the assessment estimates the aggregate production by resource category to meet the projected demand based on assumed resource availability.

4.3.1 Summary of Energy Adequacy Assumptions

The energy adequacy assessment (EAA) uses the same set of assumptions as the capacity assessment outlined in Tables 4-1 and 4-2, which indicate the total capacity of committed resources and when they are expected to be available over the next 18 months. The monthly forecast of energy production capability, based on energy modelling results, is included in the 2022 Q2 Outlook Tables.

For the EAA, only the firm scenario in Table 4-5 with normal weather demand is assessed. The key assumptions specific to this assessment are described in the Methodology to Perform the Reliability Outlook.

4.3.2 Results – Firm Scenario with Normal Weather

Table 4-5 summarizes the energy simulation results over the next 18 months for the Firm scenario with normal weather demand both for Ontario and for each transmission zone.

Table 4-5 | Summary of Zonal Energy for Firm Scenario Normal Weather

Zone	18-Month Energy Demand TWh	18-Month Energy Demand Average MW	18-Month Energy Production TWh	18-Month Energy Production Average MW	Net Inter-Zonal Energy Transfer TWh	Zonal Energy Demand on Peak Day of 18-Month Period GWh	Available Energy on Peak Day of 18-Month Period GWh
Bruce	1.2	90	64.9	4,919	63.7	1.7	137.6
East	11.7	886	17.5	1,323	5.8	23.9	104.1
Essa	13.3	1,006	3.4	255	-9.9	28.4	16.4
Niagara	6.7	507	20.7	1,566	14.0	15.2	48.7
Northeast	15.6	1,180	15.0	1,134	-0.6	27.4	39.1
Northwest	6.8	517	6.6	503	-0.2	12.1	18.9
Ottawa	13.1	995	0.6	45	-12.5	30.0	1.8
Southwest	41.6	3,153	7.5	568	-34.1	92.8	23.6
Toronto	75.1	5,688	55.7	4,218	-19.4	173.4	149.6
West	22.2	1,683	15.0	1,133	-7.2	51.2	80.9
Ontario	**207.3**	**15,705**	**206.8**	**15,666**	**-0.5**	**456.1**	**620.8**

4.3.3 Findings and Conclusions

The EAA indicates that Ontario is expected to have sufficient supply to meet its forecast energy needs throughout the outlook period for the Firm scenario with normal weather demand, without having to rely on support from external jurisdictions, with the exception of six weeks in the summer of 2023 occuring primarily in July and two weeks in August. During this period, a number of coincident generation outages suggest a possibility of unserved energy under normal weather conditions, and Ontario may require support from external jurisdictions in order to meet energy demand.

The figures and tables in this section are based on a simulation of the province's power system, using the assumptions presented within the Outlook to assess whether Ontario will be energy adequate.

Figure 4-6 breaks down projected production by fuel type to meet Ontario's energy demand for the next 18 months, while Figure 4-7 shows the expected production by fuel type for each month. The province's energy exports and imports are not considered in this assessment. Table 4-6 summarizes these simulated production results by fuel type, for each year.

Figure 4-6 | Forecast Energy Production by Fuel Type

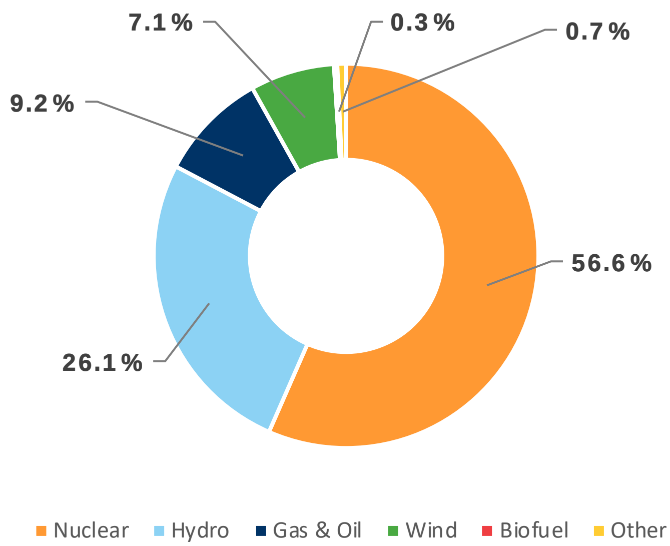


Figure 4-7 | Forecast Monthly Energy Production by Fuel Type

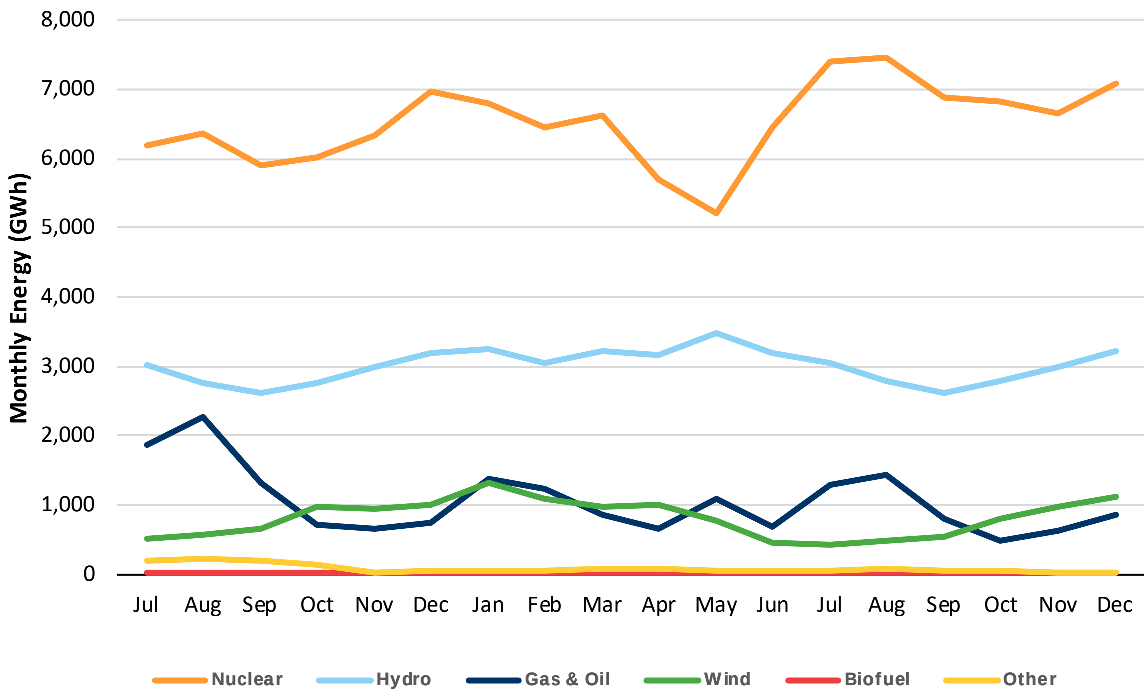


Table 4-6 | Energy Production by Fuel Type for the Firm Scenario Normal Weather

Fuel Type (Grid-Connected)	2023 (July 1 – Dec 31) (GWh)	2024 (Jan 1 – Dec 31) (GWh)	Total (GWh)
Nuclear	37,775	79,497	117,271
Hydro	17,392	36,801	54,192
Gas & Oil	7,594	11,455	19,050
Wind	4,691	10,007	14,698
Biofuel	226	360	586
Other (Solar & DR)	843	673	1,516
Total	**68,521**	**138,792**	**207,313**

Chapter 2

Economic Growth and Electrification Driving Electricity Demand

2.2 Electrification

These historic investments in EV and battery manufacturing – and many more – reflect the province's economic competitiveness and will help build our reputation as a leader in clean transportation solutions.

As of May 2023, there are more than 118,000 EVs registered in Ontario, including both battery-electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV). By 2030, there are expected to be more than one million EVs on the road in Ontario.

The IESO's 2022 Annual Planning Outlook states that electricity demand from transportation is forecast to grow from about 2 TWh in 2024 to 30 TWh in 2043, an average annual growth rate of 17 per cent. Investments in generation will ensure that energy will be there to power the future of Ontario's transportation systems.

Many of the impacts from electrification of transportation will also be felt at the distribution level. That's why Ontario is creating the right conditions to ensure the electricity system is ready for charging infrastructure, and that the charging infrastructure deployed can help reduce the impact of EVs on the grid.

The Minister's 2021 mandate letter to the OEB noted that increased adoption of EVs is expected to impact Ontario's electricity system in the coming years and the OEB must take steps to facilitate their efficient integration into the provincial electricity system, including providing guidance to LDCs on system investments to prepare for EV adoption.

Based on Minister's direction, the OEB developed its Electric Vehicle Integration (EVI) initiative to inform actions it may take to support the efficient integration of EVs and ensure that Ontario has the transmission and distribution systems to charge them. As this work continues, Ontario is also exploring ways to reduce red tape and enable the province-wide deployment of EV charging infrastructure.

Electrification will have an impact in other areas, including the increasing use of heat pumps in hybrid home heating systems, supported by government programs to reduce cost and encourage adoption.

2.3 Population Growth

Ontario's population is expected to grow by almost 15 per cent or two million people by the end of this decade. Ontario is committed to build 1.5 million new homes to accommodate this growing population.

All of these homes will require reliable electricity, especially as households increase their consumption to heat and cool their homes and power their vehicles.

Annual Planning Outlook

Ontario's electricity system needs: 2024-2043

December 2022

Connecting Today.
Powering Tomorrow.

1 Introduction

1.1 How to Interpret the Outlook

Grounded in data and market intelligence, the Independent Electricity System Operator's (IESO's) Annual Planning Outlook (APO) identifies future system needs and the factors that influence them, and provides insights into what will be required to prepare for a reliable and affordable electricity future in Ontario. The findings will inform the development of actions described in the IESO's 2023 Annual Acquisition Report (AAR), including providing inputs into the target-setting process for the IESO's upcoming acquisitions.

This outlook covers the period from 2024-2043.

The APO is intended to provide sector participants, governments, municipalities, and Indigenous communities, amongst others, with the data and analyses they need to make informed decisions, and to communicate valuable information to policy-makers and others interested in learning more about the developments shaping Ontario's electricity system.

The assumptions underpinning the APO are based on current system conditions and the best available information about demand, supply, transmission infrastructure and other factors that may influence the results of these studies. However, they do not account for many of the uncertainties in this type of forecast. In particular, the APO does not speculate on changes to Ontario's supply mix, unless they are a result of known government policy or announced actions by the IESO or its stakeholders. In reality, significant change is expected to Ontario's supply mix over the outlook period, and the results presented should therefore be interpreted with this fact in mind. By updating and publishing this analysis annually, the IESO, through the APO, better captures the evolving nature of Ontario's electricity system.

1.2 Report Contents

Section 2: Demand Forecast explores long-term demand and walks readers through the changing composition of demand by sector and the resulting effect on overall demand. It also examines the projected impact of conservation programs, building codes and equipment standards and the Industrial Conservation Initiative on reducing that demand.

Section 3: Supply Outlook and Transmission Assumptions assesses the availability of resources over the outlook period. This section also looks at the transmission projects expected to come into service within the outlook period that are considered in the base case for resource adequacy and transmission security assessments.

Section 4: Resource Adequacy compares the demand forecast with anticipated resource performance, taking into account demand forecast uncertainty, transmission constraints and the unavailability of resources due to outages and intermittent generation. This section also examines Ontario's capacity and energy adequacy.

2.3 Demand Forecast Summary

Demand forecasting focuses on understanding the causes of future changes in demand by examining demographic, economic, sector and end-use level trends. However, future changes in demand also reflect many dependencies and incorporate uncertainties that increase with the length of the outlook period. The demand forecast presented in this section considers a number of factors: all known demographic projections; sector-level market, economic announcements and trends; the current statuses and projections of large commercial- and industrial sector projects with significant electricity demand; actual grid-connection request queues; and committed policy.

With an emerging transformation of the economy driven by climate change mitigation, by fuel-switching from carbon based fuels to electrification, as well as potential economic development and policy stimulus, a high level of uncertainty is present in the 2022 APO demand forecast. An assessment of these uncertainties and their potential impacts to the forecast is outlined in Section 2.5.

2.4 Drivers of Demand

All sectors of the economy – residential, commercial, institutional, industrial, agricultural, transportation and others – contribute to province-wide energy demand. This demand forecast has been developed using sector-level segmentation and corresponding individual assessments.

A projected increase in this forecast's demand is supported by climate change mitigation and economic development policies, stable electricity rates and increasing natural gas rates, including increasing greenhouse gas emission costs, over the outlook period.

2.4.1.1. Residential Sector

Electricity demand from the residential sector is expected to show slow, steady growth over the outlook period. Several factors promote this growth, including progressive immigration policies (tempered by interprovincial emigration) that are contributing to new households, especially in communities adjacent to the Greater Toronto Area; persisting levels of work-from-home and hybrid trends, which result in higher daily household occupancy; the planned implementation of the Toronto Green Standard version 6, municipal permit requirements in 2028 to require buildings constructed in the City of Toronto on or after 2030 to be near zero emissions and continued increases in the adoption of electronics.

Overall, total sector electricity demand is forecast to grow by 20 per cent, from 50 TWh in 2024 to 60 TWh in 2043, an average annual growth rate of 1.0 per cent.

2.4.1.2. Commercial Sector

Ontario's commercial sector electricity demand is expected to be consistent with levels forecasted in the 2021 outlook. Continued slow, steady electricity demand growth continues into the medium term (years 6-10, or 2029-2033) of the outlook period, supported by a continued shift to the digital economy, which affects many sub-sectors, including hybrid office–work models in the office and hospitality sub-sectors, e-commerce in retail and warehouse sub-sectors and meal preparation and delivery services in the restaurant sub-sector. Electricity demand growth is expected to moderate to slower levels in the longer term (years 11-20, or 2034-2043) of the outlook period.

Overall, total sector electricity demand is forecast to grow from 47 TWh in 2024 to 55 TWh in 2043, an average annual growth rate of 0.8 per cent.

2.4.1.3. Industrial Sector

Consistent with the 2021 APO electricity demand forecast, Ontario's industrial sector continues to face significant uncertainty as supply chains adjust to new customer preferences and government policy. Industrial sector level electricity demand is expected to be greater than 2021 APO Reference Scenario levels, with new demand centres emerging in the province's steel-production, EV–production supply chain and hydrogen-production segments.

A number of large industrial projects are included in the forecast. Due to their size, we have included them individually, rather than as part of the aggregated numbers. The forecast for these projects includes high levels of uncertainty in terms of the precise levels of demand and the implementation timelines. Significant electricity demand growth from other projects reflected in the 2021 APO, including northern Ontario mining sub-sector growth and multiple primary metal sub-sector electric arc furnace implementations, have been confirmed with updated implementation timelines and revised demand levels. Industrial sector growth continues to be supported by local production-capability building, economic development, electrification and general GHG emissions reduction trends over the outlook period. Growth continues to be expected in all other sub-sectors, though at a slower rate than previously forecasted.

Overall, total industrial sector electricity demand is forecast to grow from 38 TWh in 2024 to 49 TWh in 2043, an average annual growth rate of 1.3 per cent.

2.4.1.4. Agricultural Sector

Demand for electricity from Ontario's agricultural sector continues to grow, driven by both greenhouse expansion and the proliferation of artificial lighting in greenhouses producing fruits, vegetables, flowers and cannabis, primarily in the West of London area. Growth is primarily in the Kingsville-Leamington and Dresden areas[4] in western Ontario. Sector-level electricity demand growth is lower than forecasted in the 2021 APO as a result of revised greenhouse-output product-mix assumptions, swinging away from cannabis and toward vegetables, with

[4] The IESO's Need for Bulk System Reinforcements West of London was published to address needs arising from the growing greenhouse demand.

lower electricity demand in the summer season. This will affect annual energy demand and summer-peak demand.

Total agricultural sector electricity demand is forecasted to grow from 5 TWh in 2024 to 8 TWh in 2043, an average annual growth rate of 2.6 per cent.

2.4.1.5. Transportation Electrification

In 2022, the Government of Canada strengthened its climate plan to shift to cleaner fuels in order to decarbonize the transportation sector. As a result, significantly more EVs will be on the road sooner in Ontario. Additionally, several rail transit electrification projects are underway across the province.

Overall electricity demand from transportation electrification is forecast to grow from about 2 TWh in 2024 to 30 TWh in 2043, an average annual growth rate of 17 per cent.

2.4.1.6. Electric Vehicles

The federal government set a mandatory target for all sales of new light-duty cars and passenger trucks to be zero emissions by 2035, with an interim target of 60 per cent by 2030, and the IESO assumes that these targets will be achieved. The number of light-duty EVs (LDEVs) on the road has increased significantly in recent years. At the end of 2021, there were 71,000 LDEVs registered in Ontario, representing 1 per cent of automobiles in the province. Policy measures, improved technology, production maturation and consumer preference contribute to the shift from internal combustion-engine vehicles to EVs. The IESO's LDEV adoption forecast is in line with federal government targets, which project 7.3 million LDEVs in Ontario by 2043.

Other types of EVs, such as electric buses and medium- and heavy-duty EVs, and their associated electricity demand, are also considered and included in the sector-level electricity demand forecast.

Besides EV adoption, which determines the quantities and types of vehicles, fuel efficiency and driving distance also have impacts on electricity demand levels. Peak sector-level electricity demand is largely influenced by charging patterns that need to and can be managed to avoid adding a significant burden on electricity system capacity needs.

2.4.1.7. Rail Transit Electrification

Mass rail transit electrification is also underway in Ontario. GO Transit rail corridors, local light rail transit projects and subway projects are at various stages of planning, construction and operation. Their electricity demands are high-level estimates for this APO and will be updated in future outlooks as more information becomes available.

Chapter 5

Integrated Energy Planning

Integrated Energy Planning

5.0 Introduction

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

Unlike previous governments, which viewed energy systems in isolation (refined petroleum products, natural gas, and electricity), the Ontario government is leading Canada in implementing an integrated energy planning process to ensure it is making the most cost-effective decisions necessary to prepare for a clean energy future.

This chapter describes the early planning process that began in 2021 with stakeholder and public consultation. The findings from that work have guided the government in creating the Electrification and Energy Transition Panel and commissioning the independent *Cost-effective Energy Pathways Study* as well as other initiatives that will inform planning, including at the IESO and OEB.

Building on the initiatives described in previous chapters, the next phase of the government's work will ensure that Ontario has the energy planning tools it requires to navigate the energy transition in a way that maximizes economic opportunities and the beneficial contribution of all parts of the energy system.

Roadmap to an Integrated Energy Strategy

The government began a review of the province's approach to long-term energy planning in 2021 to promote transparency, accountability, and effectiveness of energy planning decision-making, increase investment certainty, and ensure the interests of ratepayers are protected.

This review identified:

- The need for clear, high-level government policy direction;
- The importance of integrated, coordinated planning across energy sectors;
- A focus on independent, agency-led planning;
- The importance of independent planning oversight, with an emphasis on the role of the OEB as independent regulator; and
- The need for enhanced stakeholder and public participation.

As a result of this process, the government has taken steps to develop an integrated approach to meet Ontario's future energy needs. This has included:

- Bringing together the necessary technical advice to make informed decisions that are right for Ontario, including commissioning reports such as the *Gas Phase–Out Impact Assessment* and *Pathways to Decarbonization* by the IESO;

- Establishing the Electrification and Energy Transition Panel (EETP) and commissioning an independent *Cost-Effective Energy Pathways Study*;
- Directing the OEB to consult and report back on options to modernize Ontario's regulatory framework to support the energy transition in a cost-effective manner; implement clear guidance to LDCs to enable them to upgrade their distribution systems in preparation for electric vehicle and increased DER adoption; and to report back on distribution sector resiliency, responsiveness, and cost efficiency; and,
- Ensuring ongoing proactive planning by the IESO with support from sector entities and stakeholders.

These actions are the foundational steps the government is taking as it prepares to develop an integrated energy strategy based on additional consultation and input from the energy sector, Indigenous and local communities, and the public.

5.1 Electrification and Energy Transition Panel

Electrification and the energy transition are intensifying, driven by significant growth in electric vehicles and by corporate environmental and sustainability decisions. Electricity generation resources and transmission can take five to 15 years to develop, so early planning is increasingly critical as electricity demand growth accelerates. For these reasons, in April 2022, the Minister of Energy announced the creation of the Electrification and Energy Transition Panel (EETP) to help the government prepare Ontario's economy for electrification and the energy transition and take the necessary steps now to ensure we have the energy infrastructure to support the growing demand for clean energy.

While long-term electricity planning is important, fuel-switching will also play a key role in Ontario's evolving clean energy mix. Understanding where this is likely to occur, through integrated energy planning, Ontario will be empowered to make smart decisions that will further support lowering energy bills and create a more predictable and competitive investment environment.

The EETP will identify strategic opportunities and recommend necessary planning reforms to support emerging electricity and fuels planning needs in the context of the broader transition to a clean energy economy.

Comprised of chair David Collie and members Professor Monica Gattinger (University of Ottawa) and Chief Emerita Emily Whetung-MacInnes, former Chief of Curve Lake First Nation, the panel will advise the government on high-value short, medium and long-term opportunities in the energy sector. This includes opportunities to:

- Enable investment and job creation in Ontario by keeping energy rates low;
- Create a more predictable and competitive investment environment;
- Build on the government's work to meet energy needs and ensure a reliable, affordable and clean electricity supply; and
- Strengthen Ontario's long-term energy planning process by better coordinating the fuels and the electricity sectors.

Integrated Energy Planning

> *"Growing Ontario's economy will require growing our supply of clean energy. The Board is glad to see the Electrification and Energy Transition Panel moving forward with a strong mandate and expert members to inform a cost effective, competitive transition. This builds on the government's timely action to invest in energy storage, build Canada's first grid-scale SMR, and grow our hydrogen industry."*
>
> \- Jan De Silva
> President & CEO, Toronto Region Board of Trade

Energy Transition and Electrification Panel Themes

The EETP is exploring five key themes to inform discussions with stakeholders, Indigenous communities, and the public and guide recommendations in its final report:

1. **Energy Planning:** Improving long-term, integrated energy planning between the electricity and fuels sectors, exploring topics such as roles and responsibilities for the province and energy agencies and options to optimize energy demand and decarbonize future energy supply systems.

2. **Governance and Accountability:** Improving energy sector governance such as potential changes to agency mandates or regulatory frameworks and new performance metrics for the province and energy agencies for a successful transition.

3. **Technologies:** Improving regulatory and other frameworks and addressing barriers to core energy technologies and fuel types in energy and other sectors such as buildings, housing, transportation, industry and agriculture. Reducing barriers to low-carbon fuels, distributed energy resources and hybrid-heating solutions will be explored.

4. **Community and Customer Perspectives, Affordability and Energy Sector Objectives:** Balancing energy system costs, energy reliability and climate objectives while considering the rights of Indigenous communities, and the public interest. How citizen and customer choice and perspectives should be considered through the energy transition will be explored.

5. **Facilitating Economic Growth:** Identifying opportunities to advance economic development as it relates to the energy sector and the transition. Opportunities to improve Ontario's participation in green global supply chains and foster cross-sector collaboration in energy-intensive sectors, such as mining, steel and automotive sectors, while maintaining a cost-effective and low carbon electricity supply will be explored.

Integrated Energy Planning

Cost-effective Energy Pathways Study

To support the work of the EETP and provide key inputs into long-term energy planning, the provincial government has commissioned an independent Cost-effective Energy Pathways Study to understand how Ontario's energy sector can support electrification and the energy transition.

This study will take an integrated, multi-fuel approach to optimize technological options to prepare the energy system for electrification and the energy transition.

The Panel, the *Pathways to Decarbonization* report, the *Cost-effective Energy Pathways Study* and other research together with ongoing consultation with stakeholders and the public will help the government make strategic decisions for the future of Ontario's energy system.

5.2 Low-Carbon Fuels

While much of the public focus has centred around electrification and meeting the province's electricity needs, exciting and innovative advances in low-carbon fuels continue to provide sustainable options that in some cases may provide a more cost-effective pathway to reduce emissions in the province's broader energy sector:

- Renewable Natural Gas (RNG) - is a pipeline-quality gas that is the product of the decomposition of organic matter that after processing is fully interchangeable with conventional natural gas. RNG is commonly collected from waste facilities, sewage treatment plants and green bin programs. Further details can be found in Chapter 1.

- Synthetic Natural Gas (SNG) – is a pipeline-quality gas that is produced through the Sabatier process in which methane and water are produced from a reaction of hydrogen and carbon dioxide. If low-carbon hydrogen is used, SNG can reduce the carbon intensity of the natural gas system.

- Ethanol – is a renewable fuel made from various plant materials (often corn). Gasoline in Ontario is blended at varying percentages to reduce the carbon intensity of the fuel and reduce air pollution.

- Renewable Diesel – is a fuel made from fats and oils, such as soybean oil or canola oil, and is processed to be chemically the same as petroleum diesel. Renewable diesel can be blended with petroleum diesel or can completely replace it to reduce the carbon intensity of the fuel.

- Biodiesel - is similar to renewable diesel but not chemically the same as diesel. It is made from vegetable oils, animal fats and recyclable restaurant grease and can be blended with petroleum diesel in limited quantities.

- Hydrogen – Depending on how it is produced, hydrogen has the potential to be a low-carbon fuel and can be blended with natural gas in limited quantities to lower the carbon intensity of the fuel.

N.M9.EGI-94

Reference:

Exhibit M9, page 12
Canada Energy Regulator, Provincial and Territorial Energy Profiles, March 10, 2023[21]
Énergir website, Natural gas distribution[22]
Gazifère website, About Us[23]
Exhibit 1, Tab 2, Schedule 1, page 7

Preamble:

At page 12, Energy Futures Group states:

"As Figure 1 shows, the study concluded that natural gas use (systeme au gaz naturel) for residential space heating would be cut roughly in half by 2030 (relative to 2016) and essentially disappear by 2050. Fuel oil (systeme au mazout) and wood heating (poele a bois ou aux granules) also large disappear by 2050 in the decarbonization scenarios (Trajectories A, B, C and D). There is no hydrogen use in the residential sector in any scenario. Nor is there any appreciable use of biomethane. All space heating essentially becomes electric."

CER's website states:

"Ontario consumed an average of 2.7 Bcf/d of natural gas in 2020."[24]
"The residential and commercial sectors each consumed 0.8 Bcf/d."[25]

"In 2020, Quebec consumed an average of 587 million cubic feet per day (MMcf/d) of natural gas."[26]
"The commercial and residential sectors consumed 157 MMcf/d and 65 MMcf/d, respectively."[27]

[21] Canada Energy Regulator, Provincial and Territorial Energy Profiles, March 10, 2023, https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/
[22] Energir. Natural gas distribution. https://energir.com/en/about/our-energies/natural-gas/natural-gas-distribution
[23] Gazifère. About Us. 2023. https://gazifere.com/en/about-us/
[24] Canada Energy Regulator, Provincial and Territorial Energy Profiles - Ontario, March 3, 2023, https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html
[25] Ibid.
[26] Canada Energy Regulator, Provincial and Territorial Energy Profiles - Quebec, March 3, 2023, https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-quebec.html
[27] Ibid.

Énergir's website states:

"Its underground network spans more than 11,000 km and serves just over 205,000 customers."[28]

Gazifère website states:

"Serving more than 43 500 residential, commercial, institutional and industrial customers, Gazifère owns and operates a 1 000 km gas supply system."[29]

At page 7, Exhibit 1, Tab 2, Schedule 1 states:

"[Enbridge Gas] serves over 3.8 million residential, commercial, and industrial customers across the province" … "through 153,000 km of natural gas transmission and distribution pipelines"

Question(s):

a) Based on data provided by the Canada Energy Regulator, please confirm that the volume of natural gas used in residential buildings in Ontario was 12x the volume of natural gas used in Quebec in 2020.

b) Based on the information provided on the Énergir and Gazifère websites, and Enbridge Gas evidence, please confirm that the natural gas system in Ontario serves approximately 15x the number of customers and has 13x the amount of pipeline infrastructure as the natural gas system in Quebec.

c) Please provide any data on and compare the amount of energy delivered by the gas and electricity systems in Ontario and Quebec on a peak day. Please include sources for any assumptions.

Response

Mr. Neme has not calculated the precise degree to which Enbridge's gas system and sales are greater than Quebec's. Nor has he attempted to compare the amount of gas or electricity delivered on peak days in Ontario and Quebec. However, he readily accepts the suggestion that the gas system and gas sales in Ontario are much larger than in Quebec.

[28] Energir. Natural gas distribution. https://energir.com/en/about/our-energies/natural-gas/natural-gas-distribution
[29] Gazifère. About Us. 2023. https://gazifere.com/en/about-us/

N.M9.EGI-93

Reference:

Exhibit M9, page 12

Preamble:

At page 12, in reference to a study by the Canadian Climate Institute, Energy Futures Group states:

"The study acknowledges that there is greater uncertainty with regard to the mix of technologies and fuels that will ultimately comprise the optimal solution to decarbonization by 2050. For example, it states that electric heating systems will heat between 52% and 100% of homes by 2050 (up from about 30% today), with the balance being met by wood (0% to 10%) and clean gases (0% to 40%).[10]"

"However, the study notes that there are a number of barriers to clean gases playing even that large of a role. With respect to hydrogen, barriers include high costs, limits to the ability to blend hydrogen with methane, the "significant modifications to pipelines and distribution networks" required to carry more hydrogen than that, and the need to replace methane-burning equipment in homes and businesses with hydrogen-burning equipment. With respect to biomethane, the key barriers are both high cost and "limited" supplies of feedstock "making significant cost declines from economies of scale unlikely."[12] The bottom line is that "the future of clean gases in the buildings sector is complex and uncertain."[13]"

Question(s):

a) In the report by the Canadian Climate Institute, what are the barriers discussed regarding electrification of buildings?

b) Please confirm that the referenced report states that the percentage of Canadian homes heating with electric heat pumps in 2035 is approximately 15 to 18%.

c) Regarding hydrogen and renewable natural gas, please confirm that the referenced report states the following:

    i. A promising option for reducing emissions cost-effectively in older buildings is clean gases such as hydrogen or RNG.
    ii. The costs of hydrogen could decline by 40 to 50 percent over the next decade and up to 70 percent by 2050.
    iii. New technologies that use second-generation feedstocks could potentially drive down costs and increase supply of RNG.

iv. By 2050, clean gases could potentially provide a total amount of energy equivalent to 32 percent of today's natural gas demand from Canada's buildings.

v. The scenarios modeled in this report did not include dedicated hydrogen pipelines due to modelling limitations, which may mean hydrogen's potential contribution to final energy demand has been underestimated.

d) Please confirm that in the referenced report, the sentence that states: "The future of clean gases in the buildings sector is complex and uncertain" is followed by the following: "But the gas distribution network looks likely to play a role in helping Canada's built environment reach net zero. At a minimum, it can help to reduce emissions from Canada's older buildings over the medium term by blending in clean gases with natural gas, which can act as a helpful bridge to either eventual electrification or higher rates of blending".

Response

a) The report summarizes the challenges of reliance on electricity for decarbonization as follows: "…building the infrastructure and generation capacity necessary to meet the potential demand we indicate would require large numbers of projects, with new ones developed constantly, and often with complex environmental assessment and consultation processes. And grids, grid operations, and complementary on-demand power would all need to significantly evolve to accommodate this growth."[14] Note that all strategies for decarbonization involve challenges or barriers. If they did not, our economies would be much less GHG-intensive than they are today. Thus, when comparing different pathways to decarbonization the key issue with respect to barriers is not whether they exist for each pathway, but rather which pathways present the least challenging barriers to overcome. The referenced Canadian Climate Institute report clearly concludes that the barriers to electrification are likely to be less challenging to overcome than barriers to heavy reliance on clean gases. For example, its list of "safe bets" – which it defines as solutions that "show up consistently across all of the scenarios we examine, that rely on commercial available technologies that are already being used in some places and applications, that face no major barriers to scaling, and that have a reasonable expectation of continued cost declines" – includes energy efficiency and heat pumps, but not clean fuels.[15] In contrast, it considers hydrogen, CCUS, and biofuels to be "wild cards", defined as "technologies only in the early stages of development, that face potential barriers to scalability, or that only play a role in a subset of Canada's possible pathways to net zero."[16]

[14] Canadian Climate Institute, p. 27.
[15] Ibid., p. 77.
[16] Ibid., p. 78.

b) Figure 6[17] of the referenced report suggests that the percent of home heating provided by heat pumps would grow from 2% in 2020 to somewhere in the neighborhood of 15-18% by 2035 and to between roughly 30% and nearly 70% by 2050. Note that the report also forecasts that an additional roughly 25% to 30% of homes would have electric resistance heat in 2035 and 2050 (it is a little over 25% nationwide today).

c) Responses are as follows:
   i. The report does say that clean gases are "*a* promising option". (emphasis added).
   ii. The report does say that the costs of hydrogen could decline by 40-50% over the next decade and by 70% by 2050. However, that statement appears to refer to the cost of generating hydrogen rather than the total cost of delivering it to homes and businesses, as immediately after the statement about potential cost reductions the report discusses significant infrastructure challenges and costs.[18]
   iii. The report states that if new technologies prove viable, they could potentially help further drive down costs and increase supply of RNG. However, it also states that "the prospects for this remain uncertain." Also, the preceding sentence states that supplies of feedstocks are limited, "making significant cost declines from economies of scale unlikely."[19]
   iv. Confirmed.
   v. The modelling performed for the study did not allow for dedicated hydrogen pathways. However, given the major cost and delivery challenges associated with 100% hydrogen delivery to residential and commercial buildings that are discussed in Mr. Neme's report, it is highly unlikely that the study's hydrogen modeling constraint would have led to an underestimation of the likely role of hydrogen for such buildings. Moreover, the study also did not account for other factors, such as interprovincial grid interties and time-of-use pricing in electricity markets, either of which could reduce estimates of the economically optimal level of clean gas usage in residential and commercial buildings.[20]

d) Confirmed.

[17] Ibid., p. 39.
[18] Ibid., p. 43.
[19] Ibid., p. 44.
[20] Though addressing these limitations could allow for greater use of hydrogen in electricity generation.

CANADA'S NET ZERO FUTURE

FINDING OUR WAY IN THE GLOBAL TRANSITION

FEBRUARY 2021

CANADIAN INSTITUTE FOR CLIMATE CHOICES
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Electrification of buildings with heat pumps offers a path to net zero

Our scenarios consistently show electrification of heating as a necessary part of the transition to net zero in Canada's building sector. This will occur either via direct resistance heating (using baseboard heaters, for example) or through the use of heat pumps. Heat pumps—which function like air conditioners in reverse, extracting heat from outside air and transferring it inside—are already becoming common; in the United States, 50 per cent of new, multi-unit residential buildings use heat pumps, and more than 20 million homes globally had a heat pump as of 2019 (IEA, 2019a). Reversible heat pumps (which provide both heating and cooling) have been found to already be cost competitive in many parts of the United States compared to a gas furnace and air conditioner solution (Billimoria et al., 2018).

Buildings that combine high levels of energy efficiency and heat pumps to provide heating suited to the Canadian climate already exist in Canada. For example, a 50-unit passive house in Fort St. John, British Columbia, uses heat pumps that provide comfort in temperatures as low as -20°C (Passive House Canada, 2020).[14] Our modelling projects that heat pumps would expand from two per cent of all household heating systems today to eight to 11 per cent by 2030 and 28 to 68 per cent by 2050, while electric baseboards would hold steady, serving as the primary heating source for 24 to 33 per cent of households by 2050. In total, we estimate that electric heating systems would heat 52 to 100 per cent of households by 2050 (up from 30 per cent today). As a share of new technology sales (i.e., rather than total deployed equipment), this transition would be much quicker. Indeed, our modelling projects that in terms of sales, electric baseboards and heat pumps would overtake gas combustion furnaces between 2027 and 2032.

To make these measures ready for mass adoption in Canada, however, the nation's electrical grids would need to evolve significantly (we discuss this evolution in Box 3). The buildings sector would be both a driver of, and solution to, many of the challenges faced by Canada's electrical grids in pursuit of net zero. For example, the National Renewable Energy Laboratory in the United States has estimated that peak electricity demand would shift from summer to winter months as a result of high heat pump adoption, increasing peak demand by 20 to 33 per cent (Mai et al., 2018). These changes would likely be even more pronounced in Canada's colder climates. However, smart equipment installed in buildings could help to ease the burden of peak demand on the electrical grid. Electric water heaters, for example, can be designed to heat water when electricity prices are low, shifting demand while continuing to supply hot water.

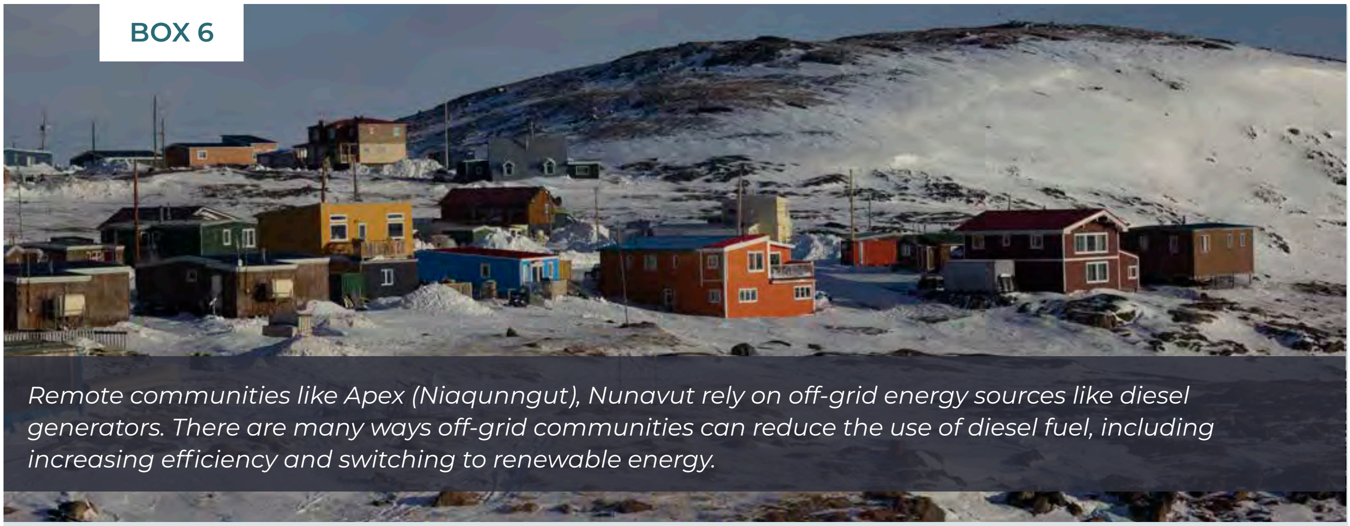
Ensuring wide adoption of heat pumps would also require supportive policy, innovative financing models, or both. In particular, low-income Canadians, including those that rent their homes, may be unable to afford energy efficiency retrofits and heat pumps without targeted support.

Electrifying building heating is likely to be more challenging in some regions than in others. Heat pumps tend to perform better in higher humidity, so their uptake might come faster in regions with more humid climates, such as eastern Canada and western British Columbia. Rural parts of Canada that have access to electricity networks

14 Supplemental natural gas heating is used for temperatures lower than this. However, such units could instead be equipped with supplementary direct resistance heating powered by electricity.

but only limited or costly access to the gas network may make the transition to heat pumps more quickly than some urban ones. In contrast, remote communities connected to neither electrical grids nor gas networks will face unique challenges and solutions, as we discuss in Box 6.

BOX 6



Remote communities like Apex (Niaqunngut), Nunavut rely on off-grid energy sources like diesel generators. There are many ways off-grid communities can reduce the use of diesel fuel, including increasing efficiency and switching to renewable energy.

Reducing diesel reliance in off-grid communities

There are 292 off-grid communities in Canada (NRCan, 2020e), many of which lack access to safe, reliable, affordable supplies of natural gas and electricity—services that most Canadians take for granted. These remote communities, nearly two-thirds of which are Indigenous, must produce their own energy locally, typically using expensive and polluting diesel generators. A recent report by the Pembina Institute estimates that approximately 682 million litres of diesel-equivalent fuel will be consumed in remote communities in 2020, equal to the annual emissions from approximately 500,000 cars (Lovekin et al., 2020).

In addition to the emissions produced by diesel generators, reliance on these systems has a range of negative social and economic implications. Air pollution and environmental leaks and spills from diesel generators harm the health and well-being of local residents (Health Canada, 2019b). Load restrictions of diesel generators limit the ability of communities to build new infrastructure, such as businesses and homes, despite growing populations. And even when subsidized, the costs of electricity in these communities can be more than double the costs for the average Canadian household (Canada Energy Regulator, 2017).

These projects can do more than provide affordable and reliable energy to communities. They can also help advance Indigenous self-determination and reconciliation, particularly when Indigenous communities have ownership of and control over projects (Hoicka et al., 2020). However, a new study that analyzed 194 renewable energy projects larger than 1 MW in size across Canada that contain some level of Indigenous community involvement found that only 41 of the projects are controlled by Indigenous communities. This raises important questions regarding whether and to what extent renewable energy activities involving Indigenous communities as currently practised contribute to reconciliation and self-determination (Hoicka et al., 2020).

Clean gases could accelerate net zero transition in the buildings sector

Electrifying building heating will be easier in new buildings than in existing ones, which may not need new heating systems for years to come. A promising option for reducing emissions cost-effectively in older buildings is clean gases such as hydrogen or RNG.[15] These fuels could be blended into the natural gas network using existing infrastructure, reducing emissions from any building connected to the network. The Alberta utility ATCO, for example, is planning to add five per cent hydrogen to one of its natural gas networks in 2021, and Fortis blends in RNG from decomposing organic matter like food waste to networks in British Columbia (Canadian Utilities Limited, 2020; Fortis BC, 2020a).

The use of clean gases is likely to vary region to region and building to building, depending on cost, infrastructure investment decisions, and local conditions, among other factors. Overall, our modelling suggests that clean gases could make an important contribution to reducing emissions from buildings with natural gas furnaces. We find that by 2050, clean gases could potentially provide a total amount of energy equivalent to 32 per cent of today's natural gas demand from Canada's buildings.

Clean gases face a number of barriers to significant uptake, however. The costs of hydrogen are high at present, although a recent wave of new investment could reduce the price of hydrogen by 40 to 50 per cent over the next decade, and up to 70 per cent by 2050 (BloombergNEF, 2020). Hydrogen also faces infrastructure challenges and costs, including the modification of existing pipelines and equipment. Without modifications, Canada's gas network can handle an average of five per cent blending, although some parts could handle much higher blends of up to 25 per cent in some instances. Going beyond 25 per cent, which would be necessary to reach net zero, would not only require significant modifications to pipelines and distribution networks but also the replacement of many of the furnaces, water heaters, stoves, and fireplaces that use natural gas today (National Research Council of Canada, 2017).

15. This does not extend to older buildings burning oil for heat, where we find that a switch to electric heat would be more economical than a transition to clean gases.

RNG, on the other hand, can be blended directly into the natural gas network at 100 per cent with no infrastructure modifications (since it is simply bio-sourced methane instead of fossil-sourced methane). But its costs also remain high. Moreover, supplies of its feedstocks are limited, making significant cost declines from economies of scale unlikely. If new technologies that use second-generation feedstocks—gasifying wood wastes, for example—prove viable, cost-effective, and scalable, they could potentially help further drive down costs and increase supply (Fortis BC, 2020b). But the prospects for this remain uncertain.[16]

Maintaining existing natural gas transmission networks would also present significant economic challenges. Under all of our modelling scenarios, we project a significant decline in total gas use—natural gas, hydrogen, RNG, and other gases combined—over time. This holds true even with population growth, primarily due to more efficient homes and competition from heat pumps. However, utilities would still have to maintain their gas networks during this time, even as their customer base declines. This would increase the cost that individual households pay for the delivery of clean gases, raising questions about the long-term economics of clean gases distributed via gas networks. It could also raise equity challenges, since households unable to absorb the cost of switching to electric heat pumps could find themselves stuck with increasingly high fixed costs for their continued use of the gas network.

The viability of clean gases will be affected by policy choices. Will governments require increasing levels of clean gas blending, as British Columbia is planning to do (Government of British Columbia, 2018)? Will Canada see large-scale public investments to make gas networks compatible with hydrogen by replacing piping with plastic, as the United Kingdom did between 1968 and 1976 to move from coal gas to natural gas?[17] Will governments change the economics of clean gas by requiring natural gas and electric utilities to merge or at least to be co-regulated? Will markets recognize the potential value of industrial, commercial, and residential retail gas networks for energy storage?

The future of clean gases in the buildings sector is complex and uncertain. But the gas distribution network looks likely to play a role in helping Canada's built environment reach net zero. At a minimum, it can help to reduce emissions from Canada's older buildings over the medium term by blending in clean gases with natural gas, which can act as a helpful bridge to either eventual electrification or higher rates of blending.

16 Engineered negative emissions solutions offer another potential path to continued gas use in buildings. Instead of reducing emissions from buildings at source by blending in clean gases, they would allow for the offset of those emissions elsewhere. However, these technologies are only in early-stage development, so their ultimate costs and availability are highly uncertain. In any case, our modelling suggests that even if they proved viable, they would only see limited uptake in the buildings sector due to the greater cost-effectiveness of available alternatives. Direct pyrolysis, or separation of methane into hydrogen and carbon residue at point of end-use, is another clean gas possibility for the buildings sector. But its prospects also remain uncertain, and its potential would only be realized over the very long term.

17 The Scottish government and the energy regulator Ofgem have recently launched a four-year pilot project that will see gas use in 300 homes converted entirely to hydrogen. Off-line trials of hydrogen transportation via gas network infrastructure will also be occurring in parallel (Ambrose, 2020).

Image credit: imantsu

Hybrid heat in Quebec: Energir and Hydro-Quebec's collaboration on building heat decarbonization

A proactive approach to the inevitable decarbonization of our energy system.

Hugo Séguin, Alex Bigouret • 14.04.23

Disclosure statement: COPTICOM, who employs the authors, acts as a consultant for Énergir.

Quebec's energy context

Two companies control almost all electricity and gas infrastructure in Quebec. The Crown corporation Hydro-Québec holds a monopoly on transmitting, distributing and purchasing electricity, and produces or buys over 90% of Quebec's hydropower. Énergir, meanwhile, distributes 97% of the natural gas used in Quebec. It is 80.9% owned by the Caisse de dépôt et placement du Québec (CDPQ)—managers of Quebec's pension plan, among other things—and the Fonds de solidarité FTQ, a labour investment fund that manages a part of the retirement savings of around 735,000 workers.

In Quebec, greenhouse gas (GHG) emissions from natural gas are practically all due to the distribution and consumption of gasdelivered by Énergir. The company intends to make its operations carbon-neutral by 2050 through the development of renewable natural gas (RNG), energy efficiency improvements on the customer end and taking a complementary approach with plans for electrification.[1]

The Quebec government has set a GHG emission reduction goal of a 37.5% decrease by 2030 compared to 1990 levels, and is aiming for carbon neutrality by 2050. It plans to achieve these objectives through major electrification of road transport, building heating and a major proportion of industrial applications.

Residential energy consumption in Quebec

In 2019,[2] natural gas represented only 13% of Quebec's energy consumption,[3] compared to 36% for Canada as a whole.[4] It is used by industry (55%), institutional and commercial buildings (28%) and residential buildings (11%), with the remainder going to other niche uses (5%). It is nearly unused in producing electricity, 99.6% of which comes from hydroelectricity and wind energy.

Residential energy consumption in Quebec is primarily electricity (74%), in addition to 12% for biofuels, 8% for natural gas and 5% for petroleum products such as oil. The majority of institutional and commercial buildings' consumption is electricity (53%), followed by natural gas (27%), oil (16%), propane and biofuels (4%). Natural gas consumption in the building and industry sectors resulted in 12 Mt CO_2 eq in 2019, or 14.2% of Quebec's greenhouse gas (GHG) emissions.

Dual energy agreement between Hydro-Quebec and Énergir

On July 13, 2021, Hydro-Québec and Énergir signed a dual energy agreement for 2022–2045. This partnership aims to convert the natural gas heating systems of Énergir customers into systems supplied by both electricity and natural gas. During cold snaps, when heating demand peaks, natural gas will be used in place of electricity, reducing the stress on the Hydro-Québec network. Outside these peak periods, buildings will be heated by electricity alone. Dual energy is a means of maximizing the role of electricity in building heating—and thereby reducing GHG emissions associated with heating—while minimizing impact during winter peaks.

Snow falling on a cold winter weather day across residential buildings in Montreal.

In Phase 1 of the agreement, around 100,000 residential customers were encouraged to convert to dual energy.[5] In Phase 2, the dual energy offer will be broadened to commercial and institutional sub-sectors.[6] The Régie de l'énergie should decide on the launch of Phase 2 in spring 2023. Note that the agreement also aims to encourage owners of new residential, commercial and institutional buildings to opt for dual energy heating systems.[7]

The agreement is supported by the government of Quebec, which has signalled to the Régie de l'énergie its desire to encourage the conversion of heating systems to dual energy (electricity and natural gas).[8] The agreement is also clearly aligned with *2023 Plan for a Green Economy* and its objective to reduce heating-related emissions to 50% of 1990 levels by the end of the decade.[9]

Any new or existing Énergir customer who wants to convert their heating system to dual energy can benefit from grants[10] covering up to 80% of conversion costs[11] from the government of Quebec and Hydro-Québec.

Dual energy conversion will reduce natural gas consumption by residential, commercial and institutional customers by over 70%,[12] while the electrification of buildings (residential, commercial and institutional) converted to dual energy will require Hydro-Québec to supply 63 MW of additional power in 2030.[13]

According to Hydro-Québec, implementing dual energy will yield savings of $1.682 billion compared to what full electrification of building heat would cost,[14] in addition to requiring that 2,070 MW of additional capacity be installed by 2030[15] at an estimated cost of $2.7 billion (see table below).

Summary table comparing the total electrification of the building sector ("fully electrical" scenario, FE) and the implementation of the dual energy agreement ("dual energy" scenario)

	Additional power required in 2030 (MW)	Additional energy required in 2030 (GWh)	GHG emissions avoided in 2030 (Mt CO_2 eq)	Share of Quebec's total emissionsin 2019 (%)	Cumulative GHG emissions avoided, 2022-2030 (Mt CO_2 eq)	Cost of scenario for the 2022-2030 period for Hydro-Québec and Énergir ($M)
"Fully electrical" scenario	2,070	2,957	0.75	0.88	3.78	2,702
"Dual energy" scenario	63	1,837	0.54	0.64	2.7	1,020

Source: Régie de l'énergie du Québec, "Décision – Demande relative aux mesures de soutien à la décarbonation du chauffage des bâtiments – Phase 1 (R-4169-2021)," Régie de l'énergie du Québec, May 19, 2022.

Énergir, for its part, will be given financial compensation (called a GHG contribution)[16] up to a cumulative total of $403 million by 2030[17] for the loss of revenues resulting from some of its customers switching to dual energy, in order to balance the impact on rates for customers of both distributors. This compensation should cover approximately 80% of Énergir's lost revenue,[18] but depends on the actual quantity of natural gas that will be replaced by Hydro-Québec electricity.

Cumulative rate impact for "fully electrical" and "dual energy" scenarios

	2025		2030	
	FE	Dual energy	FE	Dual energy
BEFORE GHG contribution				
Hydro-Québec	0.9%	0.1%	3.0%	0.9%
Énergir	2.2%	2.0%	5.0%	4.5%
AFTER GHG contribution				
Hydro-Québec	N/A	0.3%	N/A	1.4%
Énergir		0.4%		0.0%

Source: Régie de l'énergie du Québec, "Décision – Demande relative aux mesures de soutien à la décarbonation du chauffage des bâtiments – Phase 1 (R-4169-2021)," Régie de l'énergie du Québec, May 19, 2022.

Is dual energy the best way to decarbonize buildings?

At first glance, the dual energy agreement between Hydro-Québec and Énergir is an attractive mechanism for decarbonizing the building sector. It enables better management of peak power demands on the power grid while simultaneously supporting a natural gas distributor in reducing its energy deliveries. It is also more economical for Hydro-Québec than full electrification of building heating. In short, it enables all the parties involved to successfully reach a series of important economic, technical and climate objectives.

It is also a bold solution, made possible by several mutually reinforcing circumstances. First, it involves two companies with monopoly control that have set sizable decarbonization objectives for themselves. Hydro-Québec's shareholder, the government of Quebec, is likewise committed to a decarbonization timeline with milestones in 2030 and 2050, while Énergir's shareholders, the Caisse de dépôt et placement du Québec and the Fonds FTQ, are purposely working to decarbonize their investment portfolios. Finally, the solution spares the customers of both companies from rate increases, compared to full electrification of building heating.

Furthermore, the dual energy agreement approach ensures that the GHG contribution paid to Énergir by Hydro-Québec will remain in the public sphere (via the CDPQ) or at least as part of the common good (for the hundreds of thousands of Quebec residents whose retirement savings are partially managed by the Fonds de solidarité FTQ).

Nonetheless, this agreement is not without its limitations. First of all, it applies only to the building sector (responsible for 35.9% of the volume of natural gas distributed). The industrial sector, with 64.1% of the volume distributed, is left out altogether.

The agreement itself also does not include any complementary policies or instruments that might help further decarbonize the building sector and limit peak demand impacts on the power grid.[19] The government has considered or partly deployed such measures, but Hydro-Québec and Énergir have not developed a consistent and integrated approach.[20] With such an approach, it would be possible to assess whether the 30% residual heating demand that Énergir will continue to assume under the agreement could be partially or fully addressed by complementary methods.

The dual energy agreement could also lead to a certain degree of "carbon lock-in" in Quebec's building sector. Replacing heating systems at the end of their lifespan and connecting new customers to the Énergir network (and, by extension, the dual energy offer) by 2030 locks in a certain level of natural gas consumption until 2045, due to Énergir's 15-year customer contracts. What is even more concerning is that this goes against the recommendations of the International Energy Agency, including the recommendation to ban new fossil fuel boilers starting in 2025 if we want to reach net zero by 2050.[21]

Finally, Énergir hopes to use RNG to replace the remaining 30% natural gas that is necessary under the agreement, in order to reach net zero for the building sector by 2050. At this point, however, there are no indications that RNG will be available in sufficient quantity to fully replace that 30%. In 2022, for example, RNG made up only 0.6% of the natural gas distributed by Énergir.[22]

Is this an innovative model that's reproducible elsewhere in Canada?

The dual energy agreement between Hydro-Québec and Énergir bolsters the idea that a rapid reduction in the production and consumption of fossil fuels must inevitably call for large-scale systemic efforts, which here are brought about, directly and indirectly, by the action and support of the Quebec government.

The agreement was made within a specific business, regulatory and political context. Both partners' property is in large part public domain, both were already set on the road to decarbonization, and the government of Quebec has made strong commitments to fight climate change and radically reduce the use of fossil fuels. It is possible that other public utility companies elsewhere in Canada will be inspired to adapt this approach to their own networks.

Overall, with this agreement Hydro-Québec and Énergir, with the support of the government of Quebec, are taking a proactive approach to the energy transition, rather than a passive or reactive one. This may be the one of the most significant lessons to learn from this case study.

References +

[1] Énergir, "Climate Resiliency Report 2021," 2022, pp. 27–29.

[2] As data for 2021 and 2022 are not yet available, we have used 2019 data, given that 2020 was a statistical anomaly due to the COVID-19 pandemic.

[3] Johanne Whitmore and Pierre-Olivier Pineau, "The State of Energy in Quebec," Chair in Energy Sector Management – HEC Montréal, February 2022, p. 5. The data in this section are drawn primarily from this report.

[4] Canada Energy Regulator, "Provincial and Territorial Energy Profiles – Canada," July 28, 2022.

[5] Régie de l'énergie du Québec, "Décision – Demande relative aux mesures de soutien à la décarbonation du chauffage des bâtiments – Phase 1 (R-4169-2021)," May 19, 2022, p. 54.

[6] The residential sub-sector accounts for 41.5% of emissions in Quebec's building sector in 2019 (3.5 Mt CO_2 eq), compared to 58.5% for the commercial and institutional sub-sectors (4.93 Mt CO_2 eq).

[7] Régie de l'énergie du Québec, "Décision," *op. cit.*, p. 59.

[8] Gouvernement du Québec, Order in Council 1395-2022; Order in Council 874-2021.

[9] Gouvernement du Québec, "2023 Plan for a Green Economy – Framework Policy on Electrificiation and the Fight Against Climate Change," Québec, Gouvernement du Québec, November 2020, p. 6.

[10] Régie de l'énergie du Québec, « Décision », *op. cit.*, p. 78.

[11] *Ibid.*

[12] *Ibid*, p. 117.

[13] Hydro-Québec, "Offre d'Hydro-Québec Distribution et d'Énergir en réponse aux objectifs de décarbonation du chauffage des bâtiments énoncés dans le Plan pour une économie verte 2030 (R-4169-2021)," p. 21.

[14] Régie de l'énergie du Québec, « Décision », *op. cit.*, p. 51.

[15] By comparison, the total hydroelectric capacity installed in Quebec in 2019 was 40,850 MW and provided 94% of electricity for the province. Canada Energy Regulator, "Provincial and Territorial Energy Profiles – Québec ».

[16] Régie de l'énergie du Québec, "Décision", *op. cit.*, p. 11.

[17] The maximum compensation of $403 million will be paid out if all the agreement's target customers choose to convert to dual energy. Hydro-Québec and Énergir. "Réponse des distributeurs à l'engagement numéro 2 (R-4169-2021)," February 24, 2022, p. 4.

[18] Régie de l'énergie du Québec, « Décision », *op. cit.*, p. 124.

[19] In the "fully electrical" (FE) scenario, at peak times, the entire heating load is borne by electrical resistance, and there is no value added by efficient equipment. In this context, the outcome is that both scenarios rest on theoretical extremes (total electrification on one side, and complementarity between natural gas and electricity on the other) that make no effort to take into account other solutions, such as those mentioned in note 21. Hydro-Québec and Énergir, "Réponse des distributeurs à la demande de renseignements n° 1 de l'AHQ-ARQ," December 8, 2021, p. 12.

[20] Here we are thinking of dynamic pricing or smart energy technology, energy efficiency improvements through more widespread use of heat pumps, heat accumulators or thermal insulation of buildings, the promotion of low-carbon measures based on behavioural changes, or potential electricity interties. In the hearing before the Régie de l'énergie on February 21, 2022, Hydro-Québec suggested that complementary measures would be rolled out over the coming years in order to reach net zero by 2050. However, there is no evidence that this involves an integrated process, and only the replacement of natural gas by RNG was mentioned, without any consideration of whether there would be enough RNG available to replace the 30% of natural gas needed in a system converted to dual energy. Régie de l'énergie du Québec, "HQD-Énergir – Demande relative aux mesures de soutien à la décarbonation du chauffage des bâtiments – Audience du 21 février 2022 (R-4169-2021)," Régie de l'énergie du Québec, February 21, 2022, p. 73.

[21] (http://ref21) International Energy Agency, « Net Zero by 2050 – A Roadmap for the Global Energy Sector », International Energy Agency, mai 2021, p. 19.

[22] Johanne Whitmore and Pierre-Olivier Pineau, "The State of Energy in Quebec 2022," *op. cit.*, p. 32.

Quick Links

- Quebec's energy context
- Dual energy agreement between Hydro-Quebec and Énergir
- Is dual energy the best way to decarbonize buildings?
- Is this an innovative model that's reproducible elsewhere in Canada?

Recommendations

Clean Home Heating Initiative (CHHI)

The Ontario government is exploring how natural gas and electricity systems can be leveraged to further save homeowners money and reduce emissions when it comes to heating their homes.

In September 2022, the province launched the Clean Home Heating Initiative (CHHI) with funding of up to $4.5 million to bring hybrid heating to as many as 1,000 homeowners in St. Catharines, London, Peterborough, and Sault Ste. Marie. The initiative provides homeowners with incentives of up to $4,500 to install electric air-source heat pumps with smart controls. Funding was increased to $8.2 million in May 2023 and the program expanded to Barrie, Pickering, Ajax, and Whitby, bringing the total number of eligible Ontario households to more than 1,500.

With about 75 per cent of Ontario homes currently heated with natural gas, hybrid heat pumps provide the energy efficiency benefits of an electric air-source heat pump with the reliable heat of an existing natural gas furnace to help support the transition to clean energy.

A hybrid heating system also mitigates increases in electricity peak demand on the coldest days compared to an all-electric heating system and is estimated to reduce greenhouse gas (GHG) emissions by up to 2.1 tonnes of carbon dioxide equivalents each year per household.

"I thank the Government of Ontario for introducing this innovative program, which will not only help homeowners save money on their energy bills, but also help significantly reduce their emissions. It's a win-win for the wallet and the environment."

- Kevin Ashe
Mayor, City of Pickering

"A hybrid heating system can reduce a home's greenhouse gas emissions by as much as 30 percent a year while increasing the flexibility and reliability of its heating system. We appreciate the support from the provincial government, participating cities and the electricity sector for supporting this program and its ongoing commitment to energy efficiency and carbon reduction measures. Together, we are working towards a cleaner energy future."

–Sarah Van Der Paelt
Director of Marketing and Energy Conservation, Enbridge Gas

HYDROGEN STRATEGY FOR CANADA

Seizing the Opportunities for Hydrogen

A Call to Action

December, 2020

Industry and Provincial Governments will play an important role in determining which hydrogen production pathways will come to fruition in Canada, and over what timeframes.

End-Use

Domestic deployment of hydrogen is critical to supporting Canada's world-leading hydrogen and fuel cell sector, as well as to meeting climate change objectives. The earlier deployment starts, the sooner scale and user acceptance will be achieved, allowing the realization of longer-term projections on uptake and associated benefits.

Adoption of hydrogen will be focused on energy-intensive applications where it offers advantages over alternative low-carbon options. This includes using hydrogen as a fuel for long-range transportation and power generation, to provide heat for industry and buildings, and as a feedstock for industrial processes.

- **Fuel for Transportation**

Hydrogen can be used directly as a fuel in fuel cell electric vehicles, which have twice the efficiency of combustion engines and zero harmful emissions at the tailpipe. Hydrogen combustion and co-combustion engine technology is also under development as a transitional opportunity.

Fuel cell light-duty passenger vehicles are commercially available today globally, and in limited numbers in Canada. The Government of Canada has set federal targets for zero-emission vehicles (ZEV) to reach 10% of light-duty vehicles sales per year by 2025, 30% by 2030 and 100% by 2040. Canada considers battery electric vehicles (BEVs), fuel cell electric vehicles (FCEVs), and plug-in hybrid electric vehicles (PHEVs) to qualify as ZEVs. BC and Quebec have led provincially with the adoption of consumer purchase incentives for ZEVs and sales regulations. Both of these provinces have started to deploy hydrogen fueling infrastructure and light-duty FCEVs.

Battery electric vehicles are expected to take a significant portion of the market share for light-duty applications in Canada. FCEVs offer choice for consumers desiring longer range and faster fueling times and are well suited to larger passenger vehicle platforms.

Public transit agencies around the world are shifting towards low- and zero-emission vehicles. Fuel cell electric buses (FCEBs) are commercially available today, with more than 2000 FCEBs[1] in service worldwide, and approximately half of those are powered by Canadian technology. Canada has unique potential for a 'made-in-Canada' solution with New Flyer Industries and Ballard Power Systems leading the market with commercial fuel cell electric bus deployments in North America.

The zero-emission bus (ZEB) initiative[2] underway in Canada encourages government to support school boards and municipalities in purchasing 5000 ZEBs over the next five years. Canada can leverage the local supply chain to provide economic value if FCEBs are a portion of the mix. These buses are well suited to longer routes and cold weather climate that Canadian transit agencies service.

Fuel cells are expected to play a significant role in medium- and heavy-duty trucks, rail, and ships that have operations with high power demand, coupled with energy-intensive and long duty cycles. For example, heavy-duty trucks travelling long distances would require many heavy batteries, reducing the load capacity beyond that which would be acceptable to operators. Long charging times could also impact operations negatively. The improved energy density and fast fill characteristics of fuel cell electric trucks will likely make them an optimal choice for certain applications.

[1] Ballard. (2020). *Fuel Cell Electric Buses*. Retrieved from https://www.ballard.com/docs/default-source/web-pdf's/white-paper_fuel-cell-buses-for-france_final-english-web.pdf?sfvrsn=939bc280_0

[2] CUTA. (2019). *New federal government unveils its priorities*. Retrieved from https://cutaactu.ca/en/blog-posts/new-federal-government-unveils-its-priorities

There is a similar value proposition for hydrogen use in mining equipment, including material handling vehicles. Hydrogen presents an opportunity to reduce widespread reliance on diesel for mining vehicles and stationary power equipment. Hydrogen offers the added benefit of reducing harmful exhaust emissions, especially in underground mines. The Canadian Minerals and Metals Plan (CMMP) aims to capitalize on opportunities to strengthen Canada's competitive position within the global mining sector and emphasizes the importance of developing and adopting alternative energy sources, such as hydrogen.

In the near term, as costs and availability of fuel cells challenge uptake, hydrogen-diesel co-combustion in truck applications offers an alternative pathway to create the demand for hydrogen and support infrastructure development.

♦ Fuel for Power Generation

Hydrogen can be used as a fuel for power production through either hydrogen combustion in turbines or electrochemical conversion in stationary fuel cell power plants. Hydrogen provides load management, long-term energy storage, and a path to market that enables the growing use of intermittent renewables.

In the longer term, hydrogen can play a role in greening Canada's electricity grids where there is still a reliance on fossil fuels for power production. Hydrogen can also provide stability for off-grid renewables-based power solutions in remote communities and remote industrial sites such as mines that are today largely dependent on expensive, highly emitting diesel power.

♦ Heat for Industry

As a heating fuel, hydrogen is a cleaner-burning molecule that can be a substitute for the combustion of fossil fuels in applications where high-grade heat is needed and where electric heating is not technically or economically the best solution.

In Canada's oil and gas sector, low CI hydrogen can offer emissions reduction benefits in both upstream extraction (combusted as a heat source) and downstream refining (used as a chemical feedstock). For example, in upstream operations, low CI hydrogen can replace natural gas combusted to produce steam for steam-assisted gravity drainage (SAGD) in-situ bitumen production. Hydrogen can lower the CI of conventional refined petroleum products in this way and could offer a compliance pathway for the federal Clean Fuel Standard.

Other heavy industry in Canada that relies on a large amount of high-grade heat production includes cement and steel manufacturing, the pulp and paper sector, and industrial processes relying on steam production. These sectors can also reduce emissions by converting to blends of hydrogen and natural gas or pure hydrogen for heat production.

♦ Heat for Buildings

Hydrogen can play a role in reducing emissions in heating applications in the built environment. Natural gas (NG) utilities are looking to decarbonize the NG grid by introducing both Renewable Natural Gas (RNG) and hydrogen as alternative low-carbon chemical fuels. Canada's cold climate results in heating accounting for almost 80% of energy use in the home.[1] Since NG is used for both space heating and water heating, hydrogen is gaining increased attention from utilities as a low-carbon option, either as a blend with natural gas or as a replacement fuel. Several jurisdictions in Canada and worldwide are conducting pilot projects to determine the technical feasibility of blending hydrogen into existing natural gas systems. Codes and standards work will be required to support opportunities for the potential blending of hydrogen.

Due to possible technical constraints, beyond blending limits of ~20% by volume, dedicated

[1] NRCan. (2017). *Residential Sector*. Retrieved from https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/handbook/handbook_res_00.cfm

hydrogen pipelines start to become an attractive alternative. In a net-zero future where distributed combustion emissions need to be largely eliminated, hydrogen may become the new chemical fuel of choice for heating in Canada, and utilities will play an important leadership role in that transition.

- **Feedstock for Industry**

Hydrogen is used as a feedstock in several industrial processes in Canada today. Most feedstock hydrogen is currently produced via steam methane reforming.

Hydrogen is used as a feedstock for:

- Petroleum refining
- Bitumen upgrading
- Ammonia production
- Methanol production
- Steel production

The greatest use of hydrogen globally today is for refining and upgrading crude oil, where hydrogen-based processes remove impurities like sulphur and process heavy hydrocarbon chains into lighter components. The majority of hydrogen required for refining is produced on-site from either dedicated production facilities or as a by-product. Because of this integration of hydrogen production within refining facilities, production is primarily supplied by natural gas reforming methods. The most significant opportunity to reduce emissions associated with hydrogen in the oil and gas industry is retrofitting existing conversion technology with carbon capture and storage or deploying new clean hydrogen technology that does not produce CO_2.

Availability of low cost, low CI hydrogen can create new industry in Canada. This includes methanol production and liquid synthetic fuel production, an innovative process combining clean hydrogen and carbon captured from the air to produce carbon-neutral, energy-dense liquid fuels that are well suited to applications such as aviation and large marine vessels. Renewable nitrogen fertilizer production also presents an opportunity for a new Canadian industry.

Export

With worldwide demand for hydrogen increasing, the global market is expected to reach more than $2.5T by 2050. There is a significant export opportunity for Canada as energy importers are actively looking to Canada as a potential supplier.

As an energy rich nation with significant clean hydrogen production capacity, established international trade partnerships, and strategic infrastructure assets such as deep water ports and established pipeline networks, Canada is positioned to become top global supplier of clean hydrogen. A 2019 BC study shows an export potential of $15 billion by 2050 from that province alone. Another recent study indicated that hydrogen exports could reach ~$50 billion by 2050[1], doubling the economic potential of the domestic market projected for Canada in that same timeframe. With import countries looking to decarbonize their energy systems, hydrogen could contribute to a significant portion of the energy export market share in the coming decades.

Just as Canada is working to capture the global LNG export market, we can build on this experience to advance a hydrogen strategy with strong early actions and a national plan that builds on Canada's regional strengths. Taken together, we can lead in the emerging hydrogen export market.

[1] The Transition Accelerator. (2020). *Towards Net-Zero Energy Systems in Canada: A Key Role for Hydrogen*. Retrieved from https://transitionaccelerator.ca/wp-content/uploads/2020/09/Net-zero-energy-systems_role-for-hydrogen_200909-Final-print-1.pdf

Strong Energy Sector

Canada's energy sector is critical to supporting the restart and recovery of the Canadian economy as it emerges from the COVID-19 pandemic. It accounted for 832,500 direct and indirect jobs as of 2019 , with assets of valued at $685 billion as of 2019.[1]It was also , and the energy sector was responsible for directly and indirectly contributing 10.2 percent % to Canada's nominal GDP in that same timeframe.

A key component of this is the hard hit oil and gas industry, which is facing exceptional challenges due to fall in oil prices and a collapse in global oil demand because of the pandemic. Despite this, the petroleum sector remains an engine of recovery, employing 576,000 Canadians, including 11,000 Indigenous people, working in 4,500 companies across Canada.

Further reinforcing the energy sector's strength and resilience is that existing and developing energy infrastructure assets can be repurposed for clean hydrogen. For example, Canada's extensive network of natural gas transmission and distribution pipelines could act as large-scale energy storage and distribution networks for hydrogen, carrying either a blend of hydrogen and natural gas or pure hydrogen over the long term.

Storage assets such as depleted wells, saline aquifers and salt caverns can be an important enabler for wide-spread deployment by serving as permanent CO_2 storage, and potentially for storing hydrogen at scale. In addition, Canada already produces abundant hydrogen from natural gas in the oil and gas sector used for upgrading and refining petroleum products, and these hydrogen generation assets can be leveraged and combined with new assets to produce abundant low CI hydrogen.

Canadian talent in the energy sector is extensive and spans all levels of the value chain in a wide range of areas relevant to hydrogen for at-scale production. From strategic R&D in the chemicals industry, to manufacturing of components and products ranging from materials to complete turnkey solutions, to construction and service and maintenance expertise, Canada's energy labour force is well positioned to pivot to bring hydrogen into the energy fold.

Established International Collaborations

Canada has several bilateral and multi-lateral agreements in place, which formalize and strengthen collaboration with countries and regions around the world, including Germany, the EU, Portugal, and Japan. Over the last three decades, Canada has been a founding member of several international initiatives across the value chain and continues to leverage these strategic partnerships to advance global collaboration on hydrogen.

- Canada was a founding member of the IEA Hydrogen and Advanced Fuel Cell initiatives, which evolved into the current Technology Collaboration Programs (TCPs) - designed to coordinate private and public researchers to accelerate R&D, demonstrations and advance innovation on a global basis.
- Canada is a founding member and key partner in the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE). Member countries have committed to commercializing fuel cell and hydrogen technologies to address awareness and essential codes and standards.

Ontario's Low-Carbon Hydrogen Strategy

A PATH FORWARD

Ontario

III. Existing Storage and Pipeline Infrastructure

Ontario has existing and planned pipeline and storage infrastructure that can be used to store hydrogen and deliver it to homes and businesses, as it is currently being used to transport and store natural gas and RNG. Leveraging existing assets to the extent possible will help offset the need to build new storage and distribution facilities. Existing natural gas assets include:

- **Natural Gas Distribution Network:** Ontario's natural gas pipeline network currently supplies about 3.5 million homes and 340,000 businesses in the province. Ontario is also working to expand natural gas access to thousands of households and businesses across northern, rural and Indigenous communities.
- **Salt Layers:** Southwestern Ontario has geologic salt layers potentially suitable for creating large salt caverns deep underground that are currently a typical storage method for liquid hydrocarbons and hydrogen. Ontario currently has 73 active storage caverns in the Windsor and Sarnia area serving the petrochemical industry, which could be evaluated for conversion to hydrogen storage.[6] Within North America, there are three hydrogen salt storage caverns that have been in operation since 1983.
- **Underground Natural Gas Storage:** Ontario has the second largest underground natural gas storage capacity in Canada at about eight billion cubic metres.[7] This underground storage uses depleted oil and gas reservoirs.

In the future, as low-carbon hydrogen production and use increases in the province, existing underground hydrocarbon and liquified petrochemical storage facilities could be explored for potential use to store blended natural gas and hydrogen where feasible. Additional research will be required to confirm the suitability of Ontario's existing underground storage assets to new applications.

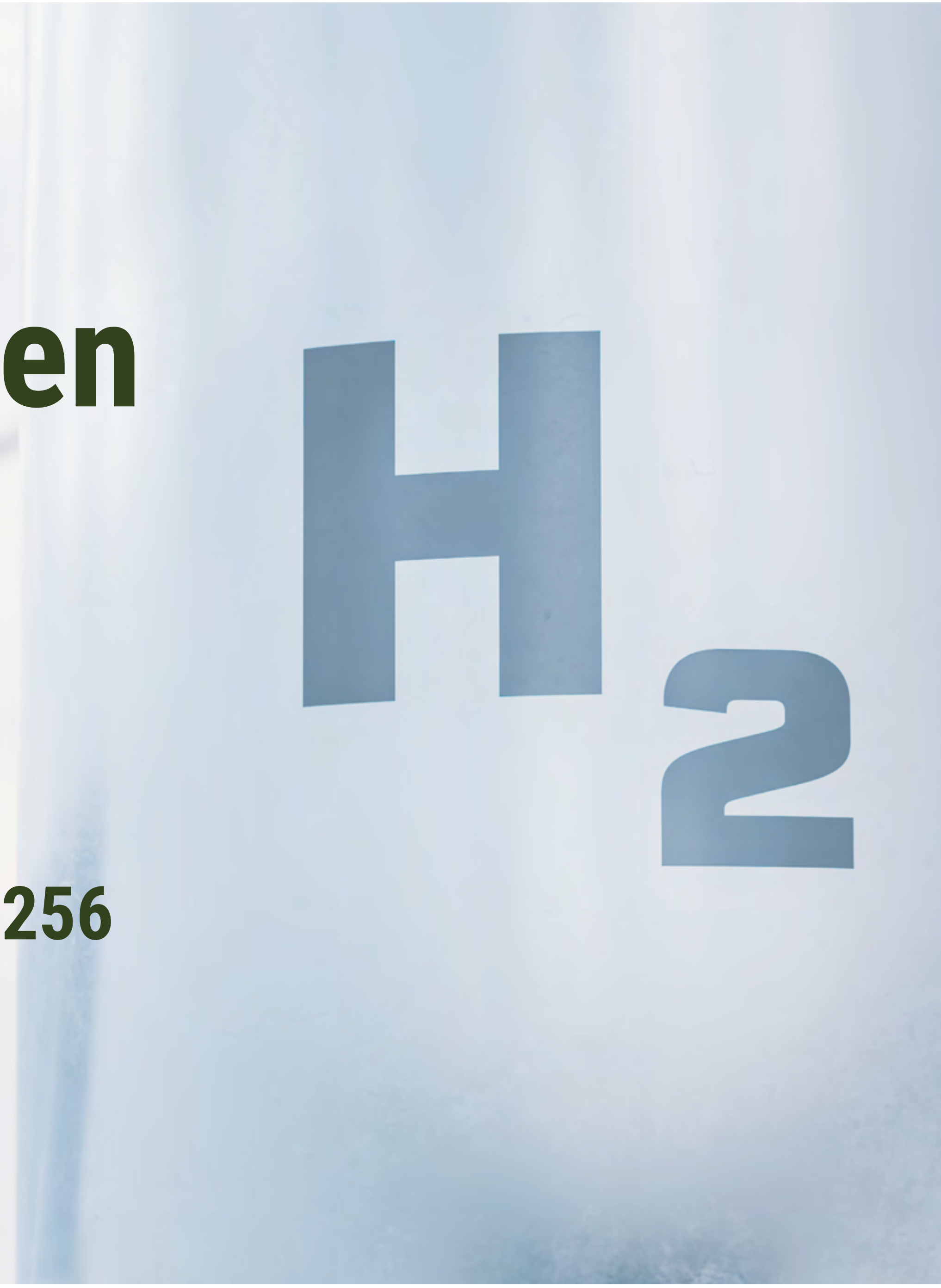
Home heating is one of the largest contributors to a household's GHG emissions. By blending low-carbon hydrogen into the natural gas system, residential customers can reduce their carbon footprint while keeping their existing furnaces, water heaters and other gas appliances. Blending projects are happening around the globe and are safe, effective ways of leveraging low-carbon hydrogen. Ontario is already home to an exciting pilot project that is blending hydrogen into the natural gas distribution system – the Low-Carbon Energy Project in Markham. The federal government, natural gas pipeline companies and natural gas distributors are reviewing codes and standards to assess hydrogen blending limits in natural gas pipelines.

6. *Ontario Petroleum Institute.*
7. *Canada Energy Regulator.*

AUC
Alberta Utilities Commission

Hydrogen Inquiry Report

Proceeding 27256
June 30, 2022



3.7.3.1 Cost allocation of different types of hydrogen

258. During hydrogen production, the level of emissions, if any, depend on the method used. As noted in Section 2.2, commonly referenced types of hydrogen include green, grey and blue hydrogen. Some parties supported that costs should be allocated in the same manner for each type of hydrogen, while others supported different cost allocation methodologies.

259. Apex and IEPS stated that the costs associated with green, blue or grey hydrogen should all be allocated in the same manner, with customers allowed to choose between these hydrogen sources. Apex submitted that utilities should be provided the flexibility to pursue various hydrogen colours to meet decarbonization mandates.

260. Direct Energy, the UCA, and CHFCA disagreed with that approach and submitted that costs should be allocated differently, recognizing that the extraction and refinement technologies used for green, blue or grey hydrogen are different, and therefore, the costs and carbon offsets may warrant distinct treatment. These parties suggested that hydrogen should be evaluated by its emissions intensity, and not its method of generation. Calgary maintained that more technical and economic information would be required to assess whether green, blue or grey hydrogen should be allocated in the same way.

261. ATCO suggested that the hydrogen production method (or colour) should not be a consideration for the AUC. Rather, it stated that, consistent with other jurisdictions, thresholds for carbon intensity of hydrogen production should be established, with the thresholds declining over time. Consideration could be given to establishing incentives or penalties for meeting or failing to meet hydrogen carbon intensity thresholds when hydrogen supply is procured; however, this must be balanced against costs to end users associated with hydrogen supply. ATCO submitted that any incentives or penalties should not hinder hydrogen blending and pilot projects in the early phases of hydrogen blending.

262. Although emissions targets are out-of-scope in this inquiry, the Commission considers that the focus of any government policy should prioritize carbon emission reductions. The Commission is of the view that further study may be required to assess the technical and economic feasibility of green, blue or grey hydrogen in order to properly allocate costs and apply the proper offset to carbon tax based on lower carbon emission intensity.

3.8 Conclusion and areas for future study

263. This report provides the Commission’s findings, observations and considerations for options on legislation, safety, and regulatory factors, which should assist the Government of Alberta’s work towards introducing a framework for hydrogen blending in natural gas distribution systems. The findings, observations and considerations are based on feedback from stakeholders on a variety of hydrogen blending-related issues and the Commission’s own expertise.

264. While numerous parties participated and provided submissions expressing various positions, limited conclusive evidence was provided on most topics. The Commission recognizes that hydrogen blending is a rapidly evolving industry, with many technical, safety and regulatory considerations that require further study before broad implementation can be realized.

265. Areas of future study identified by parties that were not examined in prior sections of the report included items outside the scope of this inquiry, such as pure hydrogen distribution systems, renewable natural gas, emissions targets that should be established, appliance safety, the blending of hydrogen in high-pressure natural gas utility pipelines, and pure hydrogen pipelines serving industrial customers. These topics are touched on below.

266. Numerous parties submitted that further consideration of pure hydrogen, renewable natural gas, and emissions targets are required.

267. The Transition Accelerator submitted that pure hydrogen pipelines and gas distribution system emissions targets should be considered, and that attention should be given to establishing a competitive open-access hydrogen market.

268. ATCO submitted that it is imperative to ensure that the full scope of decarbonization tools or gaseous energy substances are accommodated and that limiting these to hydrogen blending would result in roadblocks to decarbonization and innovation. ATCO also noted that homebuilders and developers have also been preparing for the energy transition for some time by exploring lower greenhouse gas emissions solutions and that these solutions are required to align with government policy. It stated that examples of these solutions include significantly more energy efficient building envelopes, electric vehicle ready housing, hybrid gas/electric heating, ventilation and air conditioning systems, geothermal technologies, electric heat pumps and solar photovoltaic generation.

269. While pure hydrogen and renewable natural gas are outside the scope of this inquiry, the Commission recognizes that the Hydrogen Roadmap identified the exploration and advancement of pure hydrogen communities and networks as a long-term action to implementation step[90] and considers that there may be significant benefits to further studying pure hydrogen, renewable natural gas and other decarbonization alternatives. Similarly, while emissions targets are outside the scope in this inquiry, the Commission agrees with parties that it would be beneficial if future government policy prioritized carbon emission reductions. The Commission suggests that hydrogen blending in the natural gas distribution system for use in buildings should be co-ordinated with any developments and standards related to electrification to ensure that any risks of stranded natural gas assets are mitigated. Further, the focus of provincial and federal government efforts should be to maximize carbon emission reductions, while being agnostic to the specific technology or approach to meet these ends.

270. Several parties raised concerns regarding the impact that hydrogen blending might have on appliance functionality, safety, and the associated costs. Apex stated that the performance of end-use appliances should be studied to understand at what point retrofits or replacements are required and that the Government of Alberta could consider creating a program evaluating and retrofitting or replacing natural gas appliances with appliances that can accept higher blending rates up to pure hydrogen. Similarly, ATCO submitted that the Government of Alberta should consider a hydrogen ready appliance standard to minimize long-term costs as the natural gas distribution system transitions to pure hydrogen. Gradient submitted that regulatory certainty is required on the timing of pure hydrogen distribution to allow time to develop and commercialize appliances.

[90] Exhibit 27256-X0009, Alberta Hydrogen Roadmap (2021), PDF page 46.

271. The Commission notes that Alberta Municipal Affairs has oversight over matters downstream of the meter and is the agency legislatively tasked to receive reports of accidents or damage caused by gas installation or gas equipment. Appliance safety is an important consideration for blending and could be examined further. However, the Commission agrees that safety, including for appliances, should be prioritized. Additional investigation into appliance safety and hydrogen-ready appliance standards could be conducted.

272. Other suggested areas of future study include the impact of adding hydrogen to the pipeline system for industrial facilities; using existing infrastructure such as natural gas storage reservoirs and transmission systems for blended hydrogen;, and carbon capture utilization and storage to ensure secure, permanent storage sites for carbon dioxide created by hydrogen production. NGTL asserted that technical and safety challenges may arise at higher blended hydrogen concentrations in natural gas transmission systems and that further research is required to understand these challenges. The Commission recognizes that further study of these areas will be beneficial.

273. Several parties also suggested that further action be taken following the conclusion of the Hydrogen Inquiry to assess impacts on Alberta end users as further information on the federal and provincial hydrogen roadmaps becomes available. Parties suggested that the AUC might host a technical session to better understand aspects of producing, blending and delivering hydrogen into the natural gas distribution system. In addition, continued stakeholder engagement and communication of next steps would be valuable. The Commission agrees that additional consultation may be necessary as the Government of Alberta moves forward with the Hydrogen Roadmap and hydrogen blending in low-pressure gas distribution systems.

274. Several parties identified that numerous other jurisdictions globally have experience with blending hydrogen into natural gas distribution systems. This base of experience provides a robust data set to support further investigation.

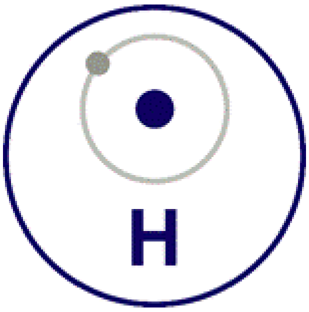
HM Government

The Ten Point Plan for a Green Industrial Revolution

Building back better, supporting green jobs, and accelerating our path to net zero

November 2020

Point 2: Driving the Growth of Low Carbon Hydrogen



Hydrogen is the lightest, simplest and most abundant chemical element in the universe. It could provide a clean source of fuel and heat for our homes, transport and industry. The UK already has world-leading electrolyser companies, and unparalleled carbon capture and storage sites that we can maximise. Working with industry the UK is aiming for 5GW of low carbon hydrogen production capacity by 2030. Hubs where renewable energy, CCUS and hydrogen congregate will put our industrial 'SuperPlaces' at the forefront of technological development. We are also pioneering hydrogen heating trials, starting with a Hydrogen Neighbourhood and scaling up to a potential Hydrogen Town before the end of this decade.

Working **alongside partners in industry, our aim is for the UK to develop 5GW of low carbon hydrogen production capacity by 2030** that could see the UK benefit from around 8,000 jobs across our industrial heartlands and beyond. This will be supported by a range of measures, including a **£240 million Net Zero Hydrogen Fund,** and setting out next year, our hydrogen business models and a revenue mechanism for them to bring through private sector investment.

The UK is already a world leader in investigating the use of hydrogen for heating, replacing fossil fuels like natural gas with hydrogen and hydrogen blends. We are keen to accelerate this work and support industry. For example, Ofgem will publish details later this month on the proposed **network demonstration** in the Levenmouth area of Fife, intended to provide hydrogen to 300 homes over a four-year period. Simultaneously, we are scaling-up the electric heat pump market, ensuring we can exploit a range of low carbon heating options available for UK consumers.

Producing low carbon hydrogen at scale will be made possible by carbon capture and storage infrastructure, and we plan to grow both of these new British industries side by side so our industrial '**SuperPlaces**' are envied around the world. We will also build on our success in offshore wind and other renewables, to bring forward the zero-carbon hydrogen of the future. Together this will develop resilient supply chains, support jobs and position UK companies at the forefront of an exciting growing global market, as well help things like industrial processes, industrial heat, power, shipping and trucking to make the shift to net zero.

Driving the growth of low carbon hydrogen could deliver...		
Support for up to **8,000 jobs** by 2030, potentially unlocking up to **100,000 jobs** by 2050 in a high hydrogen net zero scenario	Over **£4bn** of private investment in the period up to 2030	Savings of **$41MtCO_2e$** between 2023 and 2032, or **9%** of 2018 UK emissions

Policy impacts

- Aiming for 5GW Hydrogen production capacity by 2030 in partnership with industry.
- Lower carbon heating and cooking with no change in experience for domestic consumers through hydrogen blends and reducing the emissions of the gas used by up to 7%.

Target Milestones	
2021	Publish our Hydrogen Strategy and begin consultation on Government's preferred business models for hydrogen
2022	Finalise hydrogen business models
2023	Work with industry to complete testing necessary to allow up to 20% blending of hydrogen into the gas distribution grid for all homes on the gas grid
2023	By 2023 we will support industry to begin hydrogen heating trials in a local neighbourhood
2025	We hope to see 1 GW of Hydrogen production capacity
2025	Will support industry to begin a large village hydrogen heating trial, and set out plans for a possible pilot hydrogen town before the end of the decade

Case study: ITM POWER

ITM Power is a manufacturer of PEM (proton exchange membrane) electrolysers, a technology which enables the generation of hydrogen from water and are active in projects in the UK and throughout Europe. The company is based in Sheffield. Coupled with a renewable energy supply, this production method is capable of producing zero carbon hydrogen. The Gigastack project explores the potential to scale up electrolyser size and integrate those units with offshore wind facilities. BEIS is currently supporting a consortium led by ITM Power along with Orsted, Phillips 66, and Element Energy through its Low Carbon Hydrogen Supply Programme.

GOV.UK

Department for Business, Energy & Industrial Strategy

Department for Energy Security & Net Zero

Guidance

Energy Security Bill factsheet: Enabling the Hydrogen Village trial

Updated 6 June 2023

Contents

This publication is available at https://www.gov.uk/government/publications/energy-security-bill-factsheets/energy-security-bill-factsheet-enabling-the-hydrogen-village-trial

Heat in buildings is one of the biggest sources of greenhouse gas emissions in the UK, accounting for 22% of total UK emissions. Low carbon hydrogen could be a key option for decarbonising heat in buildings. Hydrogen boilers could offer consumers a heating option that works in a very similar way to natural gas, but without carbon emissions.

Why are we legislating?

The UK is already a world leader in investigating the use of hydrogen for heating, and the Ten Point Plan for a Green Industrial Revolution (2020) set out key milestones for a pioneering programme of trials. We are supporting industry to begin a neighbourhood trial, located in Fife, by 2024, and a large village trial by 2025. The trials will provide crucial evidence to inform decisions on the role of hydrogen in heat decarbonisation in 2026.

As outlined in our consultation response published in April 2022, we are now bringing forward the necessary legislative changes to facilitate the village trial (a grid conversion trial).

How the Bill will achieve this

The Bill will enable the effective and safe delivery of a hydrogen heat grid conversion trial and support protection of consumers in the trial area. It will do this by:

- Extending gas distribution network operators' (GDNs) existing powers of entry to ensure that consumers in the trial area can be safely connected to hydrogen instead of natural gas, and to cover the full range of in-home alterations which may be needed to conduct a hydrogen trial, such as replacing appliances and installing and testing safety valves. It is anticipated that GDNs will only ever use these powers of entry as a last resort to ensure consumer safety, and only once all other attempts to contact property owners and reach an agreement are exhausted;
- Enabling the Secretary of State for Business, Energy and Industrial Strategy (SoS) to make regulations requiring the GDN running the trial to follow specific processes to engage and inform consumers in an appropriate way about the trial; and
- Enabling the SoS to make regulations for the purposes of ensuring that consumers are protected before, during and after the trial.

FAQ

Will gas network engineers be able to force entry into homes in the trial area to connect them to hydrogen?

No one will be forced to use hydrogen. The Gas Distribution Network Operator delivering the trial will offer an attractive consumer offer for participants, as well as viable alternative options for consumers who do not wish to or cannot participate in the trial, such as electric cookers and heating systems.

GDNs already have powers of entry into properties, and we are only extending these powers in a very limited way specifically for the trial. These powers will only be used as a last resort to ensure homes are kept safe. The existing rules on powers of entry will apply, which require the GDN to obtain a warrant from a Magistrate's court to use them.

Will consumers pay more for hydrogen than natural gas?

Consumers will not pay more to use hydrogen than they would for natural gas and will not be expected to pay for the installation and maintenance of hydrogen-capable appliances, or an alternative heating solution.

Will the hydrogen heating trials be safe?

Safety is fundamental. As with natural gas, measures will be needed to ensure that hydrogen is stored, distributed and used in a safe way. Before any community trial can go ahead the Health and Safety Executive (HSE) will need to be satisfied that it will be run safely.

Background

In July 2021, Ofgem and BEIS published a joint letter inviting the GDNs to submit applications to Ofgem for funding to support the detailed design stage of the village trial.

We ran a consultation (Hydrogen for heat: facilitating a grid conversion to hydrogen heating trial) between August and September 2021. Following supportive responses from stakeholders, the government confirmed its intention to proceed with the proposed legislative amendments required to facilitate hydrogen heating grid conversion trials, alongside measures to strengthen consumer protections for those in the trial area.

Following an assessment period in Spring 2022, Ofgem published on 6 May a decision document announcing that the proposals from Cadent and NGN had been selected to proceed to the next stage of the project. Areas within Whitby, Ellesmere Port and within Redcar, Teesside have been identified as potential areas for a hydrogen heating village trial.

The village trial will convert a large village of around 1,000-2,000 properties to hydrogen for heating instead of natural gas. Led by the gas networks, it will trial the conversion of existing gas network infrastructure in the local area, repurposing it for 100% hydrogen.

This will involve replacing consumers' natural gas appliances with hydrogen-compatible equivalents, making any other adjustments required to properties, and piping hydrogen to premises for the trial period through the existing natural gas network, which will be appropriately modified to ensure it can safely transport hydrogen.

Further information

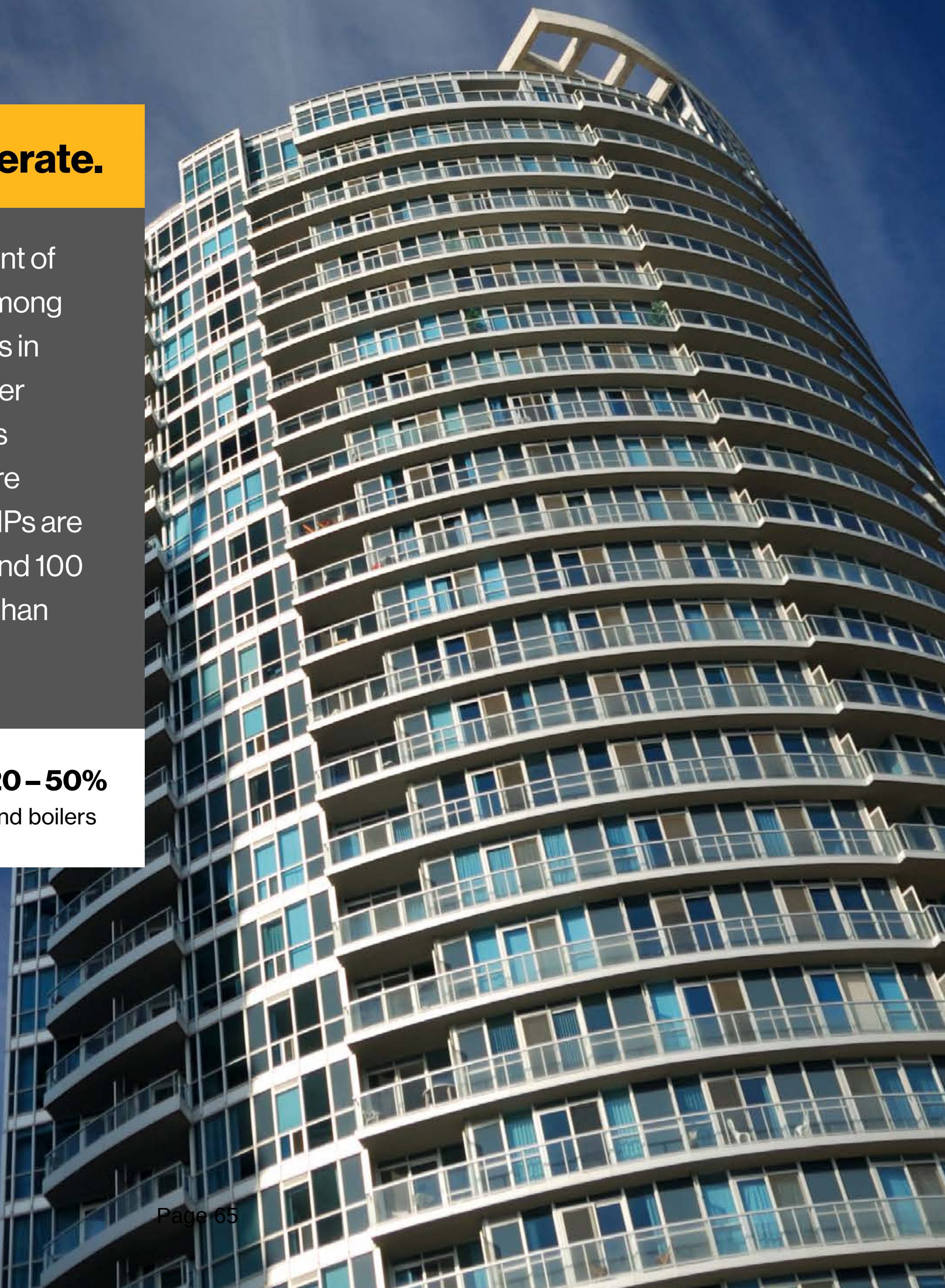
The following documents are relevant to the measures and can be read at the stated locations:

- Consultation Response (https://www.gov.uk/government/consultations/hydrogen-for-heat-facilitating-a-grid-conversion-hydrogen-heating-trial) (2022)
- UK Hydrogen Strategy (https://www.gov.uk/government/publications/uk-hydrogen-strategy) (2021)
- Heat and Buildings Strategy (https://www.gov.uk/government/publications/heat-and-buildings-strategy) (2021)
- The ten point plan for a green industrial revolution (https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution) (2020)

↑ Back to top

More comfort, less climate impact

Choose gas heat pumps for efficiency and lower operating costs



Easy to install, easy to operate.

Space heating accounts for 61 percent of greenhouse gas (GHG) emissions among commercial and institutional buildings in Canada.* Gas heat pumps (GHPs) offer an affordable way for building owners to take significant climate action. More efficient than condensing boilers, GHPs are designed to deliver efficiencies beyond 100 percent,† with lower operating costs than conventional natural gas systems.

Reduce GHG emissions by 20 – 50%
compared to natural gas furnaces and boilers

ENBRIDGE®
Life Takes Energy®

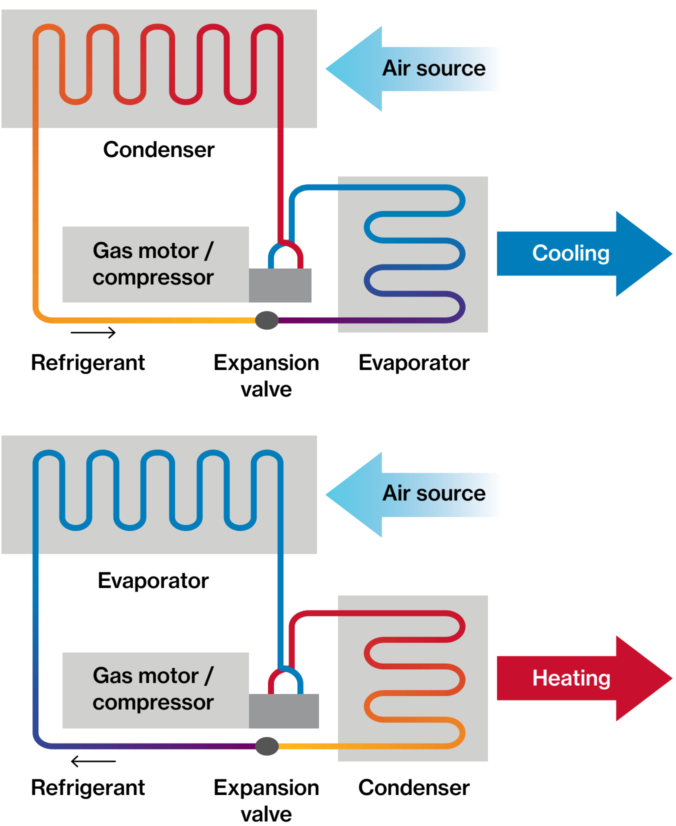
How do gas heat pumps work?

GHPs are highly efficient for space heating, hot water and even cooling. Using natural gas, they work by drawing in thermal energy from the outdoor air and transferring it in and out of buildings. This cycle of energy transfer keeps buildings warm in the winter and cool in the summer.

There are two types of gas heat pumps available for the commercial sector:

Gas-engine driven heat pumps (GEHP)

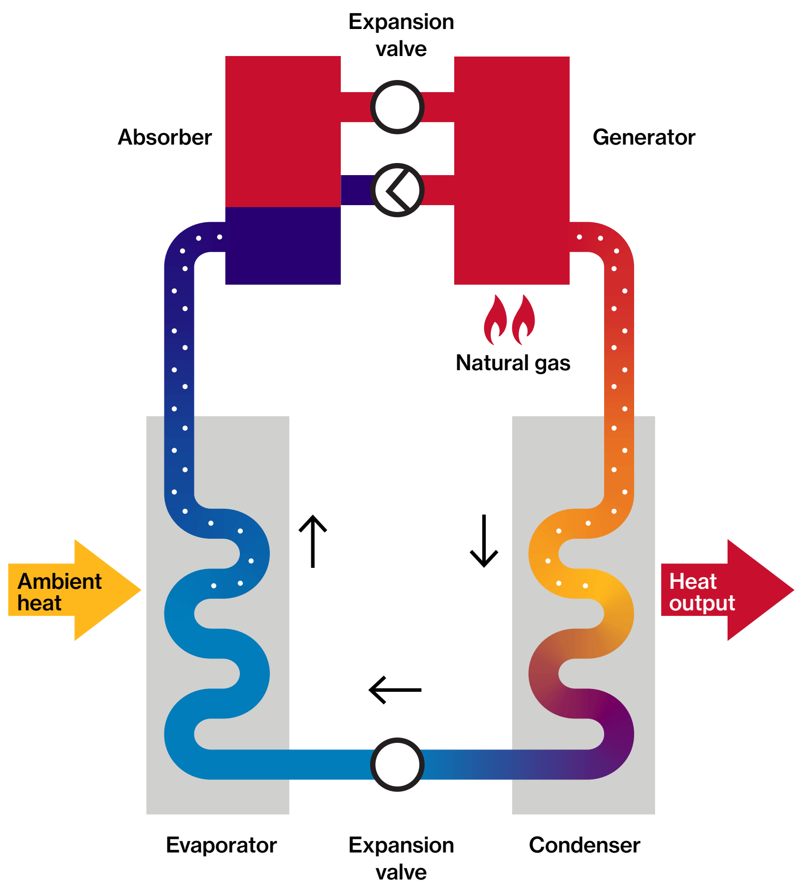
GEHPs are similar to electric heat pumps in that they supply year-round heating and cooling. They use a natural gas engine to power a compressor, which drives the refrigeration cycle.



Source: Yanmar.com

Gas-absorption heat pumps (GAHP)

GAHPs supply heat, domestic hot water and cooling. Compared to electric heat pumps, they use ammonia as a refrigerant instead of hydrofluorocarbons (HFCs). Unlike HFCs, ammonia has zero global warming potential.



Source: TAF.ca

GEHPs are ideal for:

- Office buildings
- Big box stores
- Small retail

GAHPs are ideal for:

- Multi-unit residential buildings
- Long-term care facilities
- Hotels and laundromats

5 reasons to consider GHPs

Lower operating costs and reduce energy costs from 20 – 70 percent.

Reduce GHG emissions by 20 – 50 percent.

Easy to convert to low- and no-carbon fuels such as RNG and renewable hydrogen.

Exceed codes and standards with efficiency greater than 100 percent.

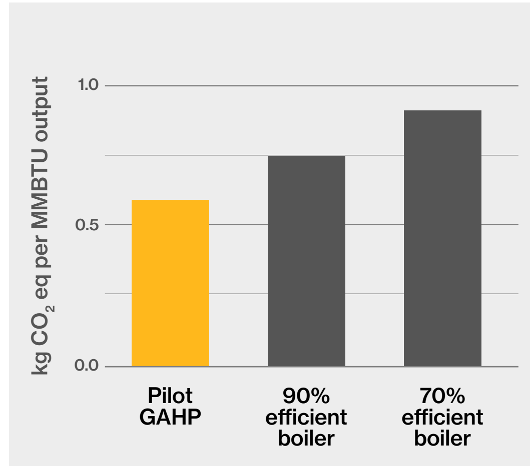
Can provide both heating and cooling using natural gas.

Did you know?

Space and water heating account for 59 percent of building sector energy use and 68 percent of building sector emissions in Canada.*

How do GHPs compare?

Compared to other natural gas heating equipment, GHPs are more efficient, reduce more emissions and are more cost-effective long-term. Compared to electric heat pumps, payback can be as short as five years.



Source: TAF.ca

Success stories

Arleta Manor, Toronto

Toronto Community Housing, The Atmospheric Fund (TAF) & Enbridge Gas

At a social housing complex for older adults in Toronto, two GAHP units help meet the building's hot water needs more efficiently and effectively, with condensing boilers providing any additional heating required to meet the temperature setpoint.

By the numbers

114% to 125% system efficiency	19 tonnes of carbon emissions are avoided annually	10,000 m^3 of natural gas are saved annually

Burnham Family Farm Market, Cobourg

The gas-engine driven three-pipe system now supplies heating and cooling to two renovated sections of a local market: its bakery and retail zones. The system is designed to transfer heat between the two areas. If the bakery zone requires cooling, the system transfers heat from the bakery to the retail zone to reduce energy demand.

By the numbers

120% to 140% heating efficiency	110% to 160% cooling efficiency	32% natural gas is saved during winter

Incentives and expert help are available

For a limited time, Enbridge Gas incentives cover 80 percent of incremental project costs for qualifying projects, up to **$40,000 per GHP unit**.‡ Whether you're considering installing a GHP or want to explore your options, get in touch with our team for expert advice and ongoing support at every stage.

- Get help planning and developing your project.
- Leverage technical expertise and assistance.
- Access incentives to help you minimize the upfront cost.

Financial incentives are available on a first-come, first-served basis, so apply soon to take advantage of this limited-time offer.

GHPs are readily available from two major manufacturers:

ROBUR® YANMAR

Connect with an Energy Solutions Advisor to get your GHP project underway

gasheatpumps@enbridge.com

* Source: Natural Resources Canada Energy Use Data Handbook (2018) † As heat pumps use energy to move heat, rather than to generate heat, the resulting efficiency in terms of heat output is greater than 100 percent. ‡ Financial incentives are only available to Enbridge Gas Inc. customers with accounts in good standing. GHP projects must achieve annual natural gas savings of at least 10,000 m^3, based on Enbridge-approved energy modelling estimates, to qualify for incentives. Please contact gasheatpumps@enbridge.com to confirm eligibility.

ENBRIDGE® Life Takes Energy®

Planning Ahead For 2030-2050

4.0 Introduction

While the Ontario government is moving forward on many fronts to secure the electricity the province needs for the decade, additional action is needed t o plan for and meet expected long-term demand between 2030 and 2050.

IESO forecasts that the need for electricity system capacity in Ontario could, under one potential scenario, more than double, from 42,000 MW today to 88,000 MW in 2050. Over this time, up to 20,000 MW in capacity may be needed just to replace generation that will come to the end of its life or be phased out.

While some forms of generation like natural gas generation or intermittent renewables can be built relatively quickly, large infrastructure which can provide baseload power such as hydroelectric, nuclear facilities, and the transmission to get it to population and economic centres, can take 10 to 15 years to build.

The Ontario government is acting now to develop new generation capacity including assessing site potential for the first large-scale nuclear build since 1993, expanding the province's SMR program, and adv ancing long-duration storage projects so that these facilities are ready when they are needed.

In keeping with its forward-thinking approach to energy planning, the Ontario government asked the IESO to deliver critical reports to inform next steps. These reports and input from Ontarians have formed the basis for the additional actions the Ontario government is taking to meet the province's needs in the longer term which are described in this chapter.

4.1 Pathways to Decarbonization

In October 2021, the Minister of Energy asked the IESO to develop a *Pathways to Decarbonization* report. Released in December 2022, the report recommends "no-regrets" actions that could be taken today to develop needed electricity resources with long-lead times.

1. Accelerating current efforts to acquire new non-emitting supply, including the implementation of recent conservation and demand management directives.

2. Beginning the planning, siting and environmental assessment work needed for new nuclear, long-duration storage and hydroelectric facilities, as well as transmission infrastructure, to allow for faster implementation.

3. Investing in emerging technologies like low-carbon fuels. Further work is needed to determine if they can replace at scale some of the flexibility that natural gas currently provides the system.

4. Galvanizing collaboration among stakeholders and Indigenous communities.

5. Ensuring that regulatory, approval and permitting processes are ready to manage future investment at scale.

Ontario (https://www.ontario.ca/page/government-ontario)

More Homes Built Faster

Learn how we're helping cities, towns and rural communities grow with a mix of ownership and rental housing types that meet the needs of all Ontarians.

Note: *More Homes Built Faster Act* received Royal Assent on November 28, 2022.

Minister's message

Ontario is a prosperous and growing province – the best place in the world to call home.

Yet for too many Ontarians, finding the right home is all too challenging. For young people, eager to raise a family in a community of their choosing. For newcomers, ready to put down roots and start a new life. For seniors, looking to downsize, but wanting to stay near their family and loved ones.

This is not just a big-city crisis. The housing supply shortage affects all Ontarians: rural, urban and suburban, north and south, young and old.

The problem is clear. **There simply aren't enough homes** being built.

And the solution is equally clear. We need to get more homes built faster.

Our government has committed to getting 1.5 million homes built over the next 10 years, and **More Homes, Built Faster: Ontario's Housing Supply Action Plan 2022–2023** is the next step to getting there.

Our policies will provide the groundwork for growth by:

- reducing the bureaucratic costs and red tape that are delaying construction and pushing home prices even higher

- promoting building up near transit and reforming zoning to create more "gentle density"
- protecting homebuyers and utilizing provincial lands to build more attainable homes

Achieving our goal will not be easy. A housing crisis many decades in the making cannot be fixed overnight.

But More Homes, Built Faster is part of a strong foundation on which 1.5 million homes can be built over the next 10 years – in partnership with municipalities, the private sector, not-for-profits and the federal government.

Our government is following through on our commitment to Ontarians and we are counting on your support as we continue to work to get it done.

Overview

The housing supply shortage is a Canada-wide problem, with many elements – such as high interest rates, construction material shortages and rising inflation – adding to the crisis.

This plan addresses the crisis by reducing government fees and fixing development approval delays that slow housing construction and increase costs. We intend to reform these processes at the provincial and municipal levels to ensure all Ontarians can find a home that meets their needs and budgets.

Building more homes

Too many people are struggling to find an attainable home that meets their family's needs. It's a complex problem that will require a range of solutions. One key element is increasing the supply and mix of houses. We need more homes of every type, from three-bedroom condos, to stacked townhouses, to secondary suites.

Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

current ROE formula would have served to increase the allowed ROE during the recent credit crisis, which, in the Board's view, would have been directionally correct.[64]

The Board has determined that it is appropriate to use a corporate yield variable that is reflective of the borrowing costs of Canadian utilities, one that is well-understood and is based on an established index from a recognized source. **The Board has** accordingly **determined that it will use a utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond index yield and the long Canada bond yield.** This is further described in Appendix B.

The Board agrees with the comment of Ms. McShane that separating the LCBF and the utility bond spread variables, as opposed to using one corporate bond yield variable that would implicitly incorporate the LCBF, provides transparency as it shows "what part is causing the ROE to move in either direction."[65]

The Board also determines that the utility bond spread reflected in the reset and refined formulaic ROE approach will be subject to a 0.50 adjustment factor, consistent with the empirical analyses provided by participants to the consultation.

4.3 Capital structure

The Board's current policy with regard to capital structure for all regulated utilities continues to be appropriate. As noted in the Board's draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals.[66] The Board's current policy is as follows:

[64] Written Comments of the Electricity Distributors Association. September 8, 2009. Schedule 4.
[65] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. Ms. McShane's presentation, p. 161.
[66] Ontario Energy Board. Ontario Energy Board Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 2

CAPITAL STRUCTURE

TANYA FERGUSON, VICE PRESIDENT FINANCE & BUSINESS PARTNER

RYAN SMALL, TECHNICAL MANAGER REGULATORY ACCOUNTING

1. The purpose of this evidence is to request approval of a change to the deemed equity thickness component of Enbridge Gas's capital structure.

2. The OEB last approved equity thickness levels for EGD[1] and Union[2] in the 2013 Rates proceedings for each utility. An approved common equity of 36% has been in place for each of EGD and Union since that time. With the amalgamation of EGD and Union in 2019[3], which formed Enbridge Gas, the deemed common equity ratio for Enbridge Gas remained at 36%.

3. Enbridge Gas believes that significant changes in the environment in which it operates have occurred since the time of the 2013 Rates proceedings. The OEB's current cost of capital policy indicates that capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals. In order to determine if its risk profile has significantly changed since 2012, Enbridge Gas retained Concentric Energy Advisors Inc. (Concentric) to prepare an independent report on the reasonableness of the capital structure currently approved by the OEB. Concentric's findings are set out in a report entitled "Enbridge Gas Inc. Common Equity Ratio Study" (the Study) and provided at Attachment 1.

4. Concentric considered changes in Enbridge Gas's business and financial risk since the OEB's last assessment (i.e. 2012). In the context of its consideration of business

[1] EB-2011-0354.
[2] EB-2011-0210.
[3] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.

and financial risk, Concentric concluded that Enbridge Gas's overall risk has significantly increased since 2012. As a result, Concentric concludes that the shift in risk profile warrants a reassessment of the Company's equity ratio.

5. Based on the increased risk profile of Enbridge Gas, Concentric recommends that the OEB approve an increase to the deemed equity ratio for Enbridge Gas from 36% to 42% to maintain financial strength and continued access to capital at a reasonable cost, and to manage the Energy Transition under a variety of economic and capital market conditions. As Concentric notes in the Study: "Our recommended equity ratio for Enbridge Gas in the upcoming rate setting period is consistent with the results of our analysis, which indicate that an increase in equity thickness is warranted. This is particularly important as the Company will need to maintain financial strength to continue accessing the debt and equity capital it needs to manage the Energy Transition under a variety of economic and capital market conditions, while providing safe and reliable service to its customers."

6. Enbridge Gas believes that an increase in its approved equity thickness to 42% is appropriate and supported by Concentric's findings. However, in order to manage the revenue requirement and rate impacts of the proposed change in equity thickness, along with the impacts of other proposals included within this Application, the Company proposes that the increase be phased in over the next incentive regulation term. As illustrated in Table 1, a 2% increase in equity thickness is proposed for the 2024 Test Year, with subsequent 1% increases in each of 2025 to 2028.

Exhibit M9-GEC-ED Energy Transition

Before the Ontario Energy Board

EB-2022-0200

Enbridge Gas 2024 Rebasing

Prepared by:

Chris Neme

Energy Futures Group

Prepared for:

The Green Energy Coalition
Greenpeace Canada
Sierra Club Ontario Chapter

Environmental Defence

May 11, 2023 (updated May 30th)

I. Executive Summary

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

1. Key Conclusions

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

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

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

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

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

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

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

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