ONTARIO ENERGY BOARD

EB-2024-0111

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

AND IN THE MATTER OF an application by Enbridge Gas Inc. to change its natural gas rates and other charges beginning January 1, 2024

COMPENDIUM OF ENVIRONMENTAL DEFENCE AND GREEN ENERGY COALITION

December 17, 2024

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EETP

ELECTRIFICATION AND
ENERGY TRANSITION PANEL

ONTARIO'S CLEAN ENERGY OPPORTUNITY

REPORT OF THE ELECTRIFICATION AND ENERGY TRANSITION PANEL

DECEMBER 2023

6.5 TECHNICAL PLANNING FOR NATURAL GAS

One of the core challenges in governing and regulating electrification and the energy transition will be maintaining clear accountability and consumer protection in the natural gas system in the face of shifting customer values and preferences and the overall shift to a clean energy economy. Natural gas has long played an important role in the energy system of Ontario, as a source of power for electricity generation, as a fuel for home heating and cooking and as a feedstock and source of process heat for industry. It is clear that natural gas will continue to play these critical roles in the short- to medium-term. Longer-term prospects, particularly for home heating, are less clear. As discussed in Section 5, emerging evidence shows that it is unlikely the natural gas system can be fully decarbonized while continuing to deliver cost-effective building heat. The development of regulatory frameworks and the evolution of natural gas infrastructure will need to align with the province's overarching clean energy economy commitment and protect customers as the role of natural gas changes in the province. A failure to align these regulatory frameworks with government's overarching policy commitments could result in significant cost hazards for customers or threats to overarching government policy commitments and an effective, orderly and well-aligned transition to a clean energy economy.

PROTECTING CUSTOMERS THROUGH THE TRANSITION

There is increasing evidence that electrification of building heating may become the more cost-effective option over time. The speed at which customers would change their heating source is uncertain and dependent on a large number of individual factors, such as equipment age and personal preferences and values, as well as system-level and policy factors, such as cost development, availability of equipment and qualified technicians, and supportive policies and incentives. Nonetheless, this could lead to many customers disconnecting from the natural gas system absent any personal motivation to lower their carbon footprint. As a result, there is a real risk of stranding assets in home heating and the gas distribution grid over the medium to long-term, with significant risk to customers, investors and public finances. As more customers exit the natural gas grid to adopt electric heating, those customers who are least able to afford to electrify could be forced to pay higher and higher proportions of the network cost to keep the system running safely.

Other jurisdictions are also grappling with these difficult policy challenges. A report on long-term gas utility planning prepared for the Colorado Energy Office in 2021 highlighted the potential cost hazards posed by traditional cost of service regulation in a future characterized by large-scale defection from natural gas heating. Those customers who can afford the higher upfront costs of heating electrification will be the first to defect from the gas system, and without regulatory changes, the remaining customers (who will tend to be lower income) could be left to shoulder the cost for the remaining gas system. Similarly, the final report of the **Massachusetts Commission on Clean Heat** highlighted how, as the state transitions to predominantly electrified building heat in the long-term, natural gas rates could go up significantly as fewer households support the system's fixed infrastructure costs. The report highlighted this hazard as an equity concern, noting that Massachusetts needed to ensure that low- and middle-income households are adequately assisted and prioritized such that they do not disproportionately bear remaining gas infrastructure costs.

Perhaps most importantly, both the Colorado and Massachusetts reports highlighted the need to consider the cost hazards of asset depreciation, regulated returns and mass grid defection in planning for natural gas system upgrades and expressions. The Massachusetts Commission on Clean Heat emphasizes that the state should avoid future investments in gas pipeline infrastructure that will disproportionately burden low- and middle-income households. The report for the Colorado Energy Office stated that the hazards of stranded assets and cost recovery should be addressed "at the level of the strategic framework" and that steps should be taken now to optimize gas system investments – using a full accounting of lifetime costs – to mitigate stranded asset risk and cost burden in the future.

Considerations like these are being incorporated into regulatory decision-making. The state of New York's Public Service Commission (PSC) is requiring planning by utilities to align with state climate goals and reflect electrification mandates and the development of scenarios to understand cost developments so that assets can be fully depreciated and are not stranded as the customer base shrinks. The cost hazards of large-scale grid disconnection were highlighted by an **expert intervenor testimony** on a rate application from a large gas utility in 2022. In that case the expert witness testified that the utility's plans would leave billions of dollars of assets at risk of stranding in 2050, when pipeline throughput will be much lower given emissions reduction requirements. Given the state's policy objectives of decarbonization and electrification, and assuming a rate of departure from the natural gas system in line with the Commission's gas planning order, the expert witness' modeling indicated that average annual household gas delivery bills could more than triple by 2050 to support the system and cost recovery. These effects could in turn push more customers to exit the gas grid. As gas rates increase, the economics of electrification become more favourable for customers, and as each additional household electrifies or otherwise substantially reduces their use of pipeline gas, more rate pressure is added on remaining customers, perpetuating a vicious cycle. The witness stated that this risk could be mitigated, and thus costs avoided, by reducing the scope and scale of the pipeline enhancement or by shortening the depreciation lifetimes for new assets to align with their expected utilization timeframes.

Each of these cases is shaped by the unique market and regulatory characteristics of the jurisdiction, but the basic conundrum is a general one. A **submission to the (OEB) on behalf of the Industrial Gas Users Association (IGUA)** filed in August 2023 identified the same issues and advocated that decisions about the funding, utilization and maintenance of gas system assets be made at a system level in planning frameworks. In the rate case currently before OEB Commissioners, staff submitted that the revenue horizon for an economic feasibility assessment should be shortened from 40 years to 20 years, with implications for higher contributions in aid of capital. Staff also submitted that the natural gas utility should be required to provide more information and analysis on energy transition assumptions in load forecast and include forecast risk and stranded asset risk in its cost-benefit methodology for integrated resource planning. This issue will require careful governance intervention to ensure a well-managed transition that maintains affordability and protects customers.

It is quite possible that customers will withdraw from the natural gas grid at a different and much slower pace than the one outlined above. This alternative scenario could involve a plausible future with a significant emphasis on hybrid heat - using heat pumps and natural gas furnaces and boilers - rather than a full switch to heat pumps. In that case, the volume of gas sent through the natural gas distribution grid would decrease substantially, but the ongoing fixed costs to maintain the grid would continue to be split among a large and largely stable number of customers.

In either case, it is in the interest of the province, for the purpose of customer protection, to ensure that the regulatory mechanisms for the governance of the natural gas grid are aligned with a range of plausible outcomes, notably those that pose the greatest risks to customers. Other contextual risk factors should also be considered, such as societal, economic, or technological trends that may have an impact on future natural gas demand. Careful consideration of asset lifetimes, contingency planning for infrastructure expansion and enhancement proposals and stress-testing cost allocation mechanisms will be crucially important should a high-defection scenario come to pass. And such steps will not threaten the cost-effectiveness of the natural gas system in a scenario of prolonged reliance on the natural gas grid.

It will be critical, in the interest of customer protection, to further develop the province's regulatory framework so that it is prepared for a range of possible outcomes and that in so doing, it can contribute to Ontario's clean energy economy goal. The use of scenarios in the development of corporate strategy as well as regulatory decisions and government policy will enable Ontario to be prepared for a range of possible paths, driven by government policy, technological developments, market realities, and customer actions. Scenario-based analysis can also contribute to an open and transparent debate about opportunities and risks in the energy transition.

A FRAMEWORK FOR GAS-ELECTRIC COORDINATION

In the past, different energy demand applications were fairly closely associated with specific energy sources. The increase in electrification options, not just building heating discussed above but also transportation, steel making and others, means that customers now have options regarding the energy source they want to use to satisfy a certain demand. They can fuel-switch. This is, in fact, a general feature of energy transitions. As a result, shifts in customer consumption patterns regarding one source of energy, whether as a result of social, economic, technical or policy developments, have repercussions for planning and balancing the energy supply and demand of other systems.

The Panel heard consistently that electrification and the energy transition will require greater technical co-ordination for the planning of Ontario's electric and natural gas systems. Natural gas and electric systems are currently planned and regulated separately. Moving forward there is a need for coordination on an aligned vision, and for integrated planning and shared forecasting to understand the effects of fuel switching for infrastructure planning and development, and opportunities for system optimization across the electricity and natural gas delivery systems. Coordination will require sharing data and assumptions, aligning on demand forecasts, developing possible alternative scenarios, analyzing system capabilities to supply demand from fuel switching, integration of electric and natural gas efficiency and demand response programs, and coordination on the timing and location of new infrastructure development and asset refurbishment. Given the interests and tensions inherent in such a process – as well as the potential impacts on agency functions – the OEB and IESO will need to carefully support and maintain involvement.

Such a coordinated approach can not only enhance the efficiency of planning but also reduce the load on future adjudicative hearings. Electricity and natural gas planning coordination thus represents an innovation in anticipatory governance that has the potential to greatly enhance efficiency and expedite the process of energy planning and a cost-effective energy transition.

POLICY-ALIGNED REGULATORY MECHANISMS

With increased ability to fuel-switch comes the need to ensure there is a level playing field between gas and electric regulatory systems and that those funding mechanisms for cost-recovery and up-front capital requirements are aligned with the broader policy commitment for a clean energy economy.

New Proposal for An Electricity Energy Efficiency Programming to Promote Beneficial Electrification

ERO (Environmental Registry of Ontario) number	019-9373
Notice type	Policy
Posted by	Ministry of Energy
Notice stage	Proposal
Proposal posted	November 8, 2024
Comment period	November 8, 2024 - December 8, 2024 (30 days) Closed
Last updated	November 8, 2024

This consultation was open from:

November 8, 2024
to December 8, 2024

Proposal summary

The Ministry of Energy and Electrification is proposing beneficial electrification (BE) programming under the proposed 2025–2036 electricity energy efficiency framework to help reduce energy use and overall emissions and increase ways to save Ontarians money.

Proposal details

Context

Ontario currently offers a suite of electricity energy efficiency (EE) programs that are funded through electricity rates to address electricity system needs and help customers reduce their electricity consumption and bills.

On October 4, 2024, the Ministry of Energy and Electrification (ENERGY) posted a proposal to the Environmental Registry of Ontario (ERO) regarding an electricity EE framework to launch in 2025 that would support affordability, optimize delivery and launch new programs to provide more customer choice and savings while also helping to address Ontario's growing electricity needs.

On October 23, 2024, ENERGY posted a proposal to the ERO which outlined legislative amendments to the Electricity Act, 1998 that would enable the IESO to administer enhanced energy efficiency programs that support beneficial electrification (BE) – the use of electricity instead of other fuels to reduce overall energy use and emissions and subsequently reduce costs for high consumption activities such as home heating and cooling, regardless of fuel type.

Proposal

ENERGY is now seeking feedback on the proposed BE programming that would be delivered by the IESO starting in 2025, if the required legislative amendments are approved by the Legislature and associated regulatory instruments receive all required internal approvals. This programming would be coordinated with other EE programs offered by the IESO and would be targeted towards offering electricity measures non-electric end-uses (such as electrification of space and water heating).

This programming would be funded through electricity rates to provide direct assistance to customers to participate in electrification and help reduce their overall energy costs and emissions.

Environmental Impact

The ministry considered its statement of environmental values in application to the proposed BE programming.

BE programming would provide incentives to adopt clean electricity measures for use in daily life and provide consumers with more options to reduce their overall energy use without compromising comfort while reducing their energy bills and carbon footprint.

Supporting materials

Related links

- Electricity Act, 1998 (https://www.ontario.ca/laws/statute/98e15)

Related ERO (Environmental Registry of Ontario) notices

- 2025–2036 Electricity Energy Efficiency Framework (/notice/019-9235)
- Proposed Amendments to the Electricity Act, 1998, Ontario Energy Board Act, 1998 and the Energy Consumer Protection Act, 2010 to enable an affordable energy future (/notice/019-9284)

View materials in person

Some supporting materials may not be available online. If this is the case, you can request to view the materials in person.

Get in touch with the office listed below to find out if materials are available.

Comment

Commenting is now closed.

The comment period was from November 8, 2024 to December 8, 2024

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CANADIAN CLIMATE INSTITUTE
L'INSTITUT CLIMATIQUE DU CANADA

HEAT EXCHANGE

How today's policies will drive or delay Canada's transition to clean, reliable **heat for buildings**

JUNE 2024

Based on this analysis, several insights emerge. Overall, the model's cost optimization consistently shows that achieving net zero in Canada will require a significant increase in the use of electricity for building heat, and a declining use of gas, starting right away.

Continued inertia poses risks to achieving Canada's climate goals and ensuring affordability and reliability through the energy transition.

Despite some recent progress, Canada's buildings sector and its electricity and gas systems are not yet on that cost-optimal net zero path. We find that this is unlikely to change under current policy and regulatory approaches, and that continued inertia poses risks to achieving Canada's climate goals and ensuring affordability and reliability through the energy transition.

Finding 1

On a cost-optimal pathway to net zero, electricity will power most space heating in Canada

The details vary from province to province, but the pattern is consistent across all regions and in all sensitivity scenarios: as Canada's energy transition accelerates, electricity will power more and more space heating in Canada. Heat pumps with electric resistance backup are often the most cost-optimal long-term pathway—even considering the significant electricity system build-out that they require. This finding is broadly consistent with other major Canadian and global studies that have investigated the same topic.

Mitigating peak demand to keep electricity affordable and reliable will likely emerge as the central challenge facing electric utilities in this transition. Our modelling finds that in the buildings sector, retrofits of existing buildings, the rising energy efficiency of new buildings, and the switch from electric baseboards to much more efficient heat pumps can all contribute to reducing the scale of the necessary electricity system build-out. Hybrid systems, which maintain existing gas connections as a backup to electric heat pumps, play a role in some contexts to mitigate peaks in winter electricity demand. And other options like heat and energy storage, thermal energy networks, and demand-side management will also likely play an important role.

Finding 2

Even with low-carbon gases or hybrid heat, continued expansion of the gas network is inconsistent with cost-effectively reaching net zero

Given the rapid shift away from gas consumption in buildings along a cost-optimal pathway to net zero, provinces that continue to expand their gas distribution networks risk significantly raising the cost of meeting climate targets, putting targets in jeopardy, or both. Additional expansion of the gas system to new homes or neighbourhoods is risky for ratepayers because it can lock in higher-cost ways of delivering heat to homes and businesses, or result in stranded assets that gas consumers must still pay off.

Hybrid heat (the pairing of heat pumps with gas furnaces) does not justify continued expansion of gas networks. Hybrid heat can be a legitimate stepping stone to full electrification in some contexts, and a viable long-term pathway in others—especially when furnaces are burning low-carbon gases. But because hybrid systems would only switch to gas in the coldest days or months, overall demand for gas would still fall dramatically, so expansion poses the same risks for ratepayers.

Likewise, low-carbon gases like hydrogen and biomethane will not serve as replacement fuels on a scale that can justify continued gas network expansion. Our modelling and numerous other studies find that these gases are either too scarce or too costly to heat more than a small fraction of Canada's buildings, and are instead taken up by other sectors such as heavy industry. Even under lower-cost assumptions for these fuels, electrification of building heat still dominates.

Finding 3

A business-as-usual approach to utility regulation is not in the interest of ratepayers

In the energy transition, gas utilities' incentives do not necessarily align with what is most affordable for ratepayers over the long term. Because gas utilities realize returns primarily on the infrastructure they install, rather than the fuel they sell, and because they earn a predetermined rate of return on regulator-approved capital investments, these entities have a direct economic incentive to pursue continued growth of gas infrastructure and new customers—even if the long-term usage case is uncertain.

1.1 Overarching insights for Canada’s energy systems

Overall, the model’s cost optimization consistently shows a significant increase in the use of electricity for building heat, and a declining use of gas. This pattern is robust across the sensitivity analyses we ran, and consistent with other, similar net zero studies. We unpack these findings in more detail below.

Electrifying almost all building heat is the most cost-effective path to net zero

In all provinces and across all sensitivities, a cost-optimal pathway to net zero for the economy results in electricity becoming the dominant energy supply for building heat. Nationally, electricity’s share of annual space heating energy demand rises from 21 per cent today to between 55 and 60 per cent by 2040 and between 78 and 91 per cent by 2050.

Electrification uptake varies by region, by sector, and by building type, but in almost all scenarios, getting to net zero means that electric technologies—led by heat pumps—heat most of Canada’s residential buildings by 2050. Electric end-use technologies play a major role in commercial buildings as well—including in hybrid systems where heat pumps provide the bulk of heating needs. (For a description of end-use technologies for building heat, *see Table 1*).

In all regions, the model results show significant heat pump uptake in the residential buildings sector, including heat pumps deployed as part of a hybrid system (*see Figure B*). Heat pumps and electric resistance heating are the cost-optimal technologies for the system in the vast majority of homes by 2050. Widespread electrification of heat on a cost-optimal pathway occurs in part because heat pumps are so much more energy efficient than gas furnaces. When considering the broader economic impacts of the energy system, the alternative of using hydrogen or biomethane in buildings leaves less of those low-emission fuels available for other uses where they are highly needed, such as in heavy industry.

Electric end-use technologies gain significant market share in residential space heating by 2050, even in provinces that mostly heat with gas now, such as Alberta, Saskatchewan, and Manitoba. Under the cost-optimal pathway, some of these regions deploy hybrid heating systems that pair electric heat pumps with a back-up gas furnace. Alberta sees the highest uptake of hybrid systems at 35 per cent of market share in 2050, compared to an average of 14 per cent across Canada. We discuss hybrid systems in greater detail in *Section 1.2*.

Provinces with little to no existing gas infrastructure, including Nova Scotia, New Brunswick, Prince Edward Island, and Newfoundland and Labrador, see all-electric end-use technologies (heat pumps and electric resistance heating) grow to make up nearly all of their residential market share by 2050.

The electrification of space heating in commercial and institutional buildings is more varied across provinces compared to the residential sector. Commercial and institutional buildings use a greater range of technologies, such as geothermal heat pumps, thermal energy networks, and hydrogen boilers, but only in some provinces. They also see a higher uptake of hybrid heating systems.

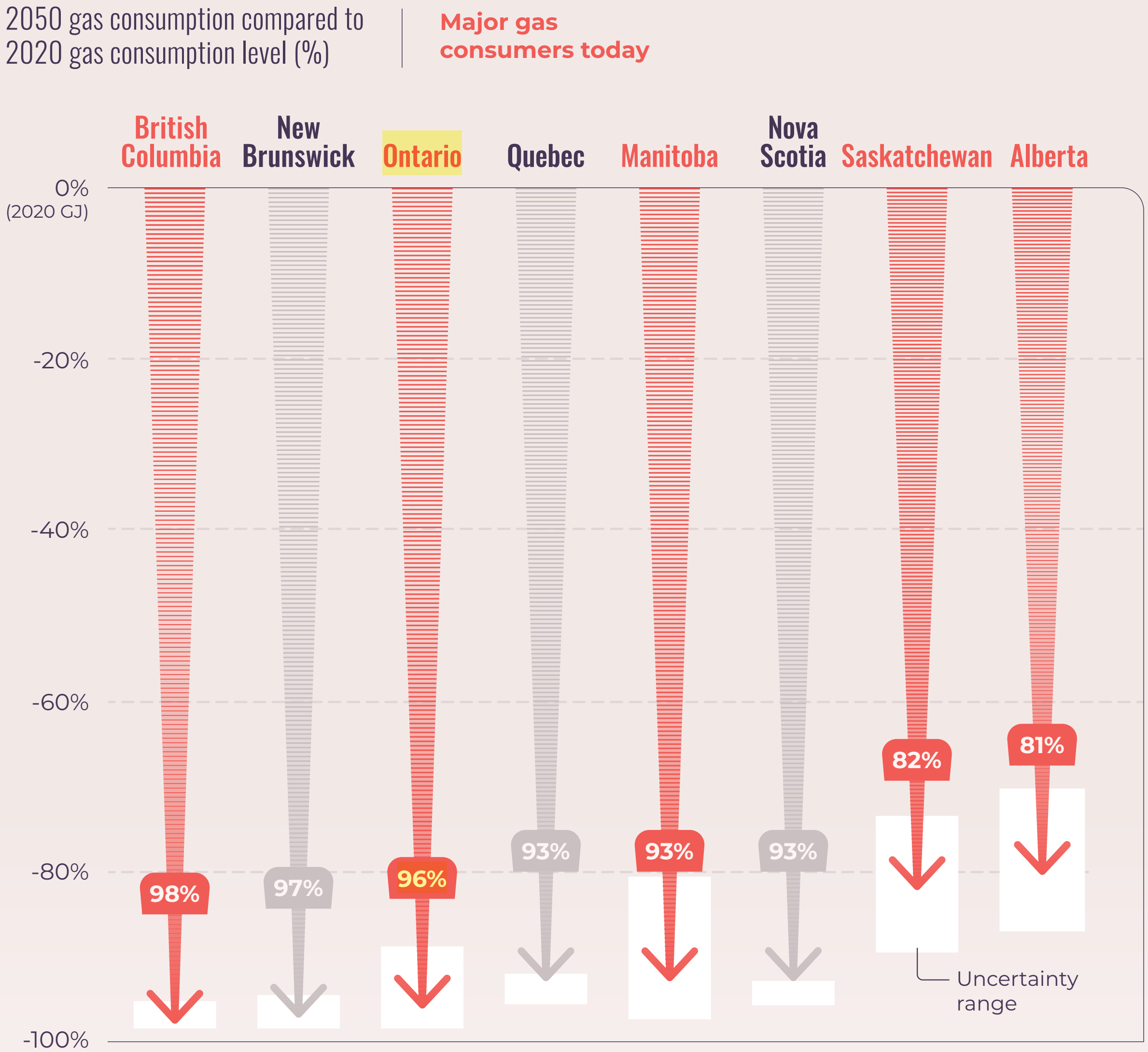
This finding of high rates of electrification is robust across sensitivity analyses. Under a sensitivity analysis that tests a lower range of efficiency improvements for heat pumps, the results show slightly lower overall electrification levels, but electricity still meets 78 per cent of annual space heating energy demand by 2050. Even under sensitivity analyses that combine lower costs and greater availability of low-emission gases with higher costs for electric end-use technologies, a widespread shift to electric building heat still tends to be more cost-effective than significant use of low-emission gases in the buildings sector.

Similarly, sensitivity analyses testing the possibility of higher biomethane feedstock availability and lower costs of biomethane production do not decrease the proportion of building heat provided by electricity.

As for hydrogen, we find that even assuming lower supply and end-use technology costs and setting blending rates to 20 per cent does not materially impact the rate of electrification of building heat. Adjusting assumptions on the costs of end-use hydrogen technologies to 50 per cent lower than baseline assumptions only shows an effect in the commercial sector: a 12 per cent increase in the market share of hydrogen technologies, and a corresponding decline in the market share of hybrid systems. The market share of full-electric technologies is unaffected. Reducing the costs of production by 30 per cent from the baseline assumption also shows no impact on the share of hydrogen technology uptake.

Figure C

On the path to net zero, buildings sector gas use declines in all provinces



HYDROGEN AND BIOMETHANE

Hydrogen and **biomethane** are two alternative gases that could be used for building heat. **Hydrogen** can be produced with fossil fuels or electricity, with lower greenhouse gas intensity if it is coupled with carbon capture technology or produced using renewable electricity (*IEA 2023b*). Hydrogen can be used in fuel cells, or burned to produce energy. It is not, however, a full substitute for methane gas—at any pressure, the volumetric energy density of hydrogen is about one third that of methane. To date, Canadian gas utilities have only tested low-percentage blends of hydrogen in existing gas infrastructure.

Biomethane, also called renewable natural gas or RNG, is a form of biogas that is produced from anaerobic digestion or direct gasification of organic feedstocks such as wood and crop residues, manure, corn silage, or pulp mill sludge. Once it is refined, biomethane can be injected directly into existing gas distribution infrastructure and burned in any existing gas space heating equipment.

The decline in gas use on a cost-optimal pathway to net zero is consistent across various sensitivities, including those that test lower cost and higher availability assumptions for low-emission gases. Under low-cost assumptions for hydrogen, more hydrogen furnaces and boilers are deployed in commercial buildings in Alberta, Saskatchewan, and Manitoba. However, total gas consumption from the buildings sector in these provinces still drops by 70 per cent in Alberta, 73 per cent in Saskatchewan, and 80 per cent in Manitoba. Under a sensitivity analysis that tests higher assumptions for the availability of biomethane feedstocks, the results show similar levels of biomethane use in buildings; the additional feedstocks are more cost-optimally used elsewhere.

This finding of declining gas demand for space heating is consistent with other net zero studies. For example, the Canadian Energy Outlook report shows that gas use in the buildings sector falls in all net zero scenarios; gas consumption is projected to decline and be only 4 to 8 per cent of 2016 demand by 2050 (*Langlois-Bertrand et al. 2021*). Studies in other countries have reached similar conclusions; for example, Guidehouse's Decarbonisation Pathways for the European Building Sector shows that, in a highly electrified pathway, gas is no longer used in buildings by 2050, and even in a pathway that deploys more hybrid systems and low-emission gases, gas demand still declines by 70 per cent by 2050 (*Guidehouse 2022*).

The levels of gas decline estimated by the NATEM model may even be an underestimate, due to limitations in how it captures the potential dynamics of gas-demand decline. The model can identify where it is most cost-effective to switch from gas to electricity to meet emissions targets, but it does not account for how falling gas demand could raise costs for remaining customers—leading to further customer defection. This can create a negative feedback loop, in which customer defection from the gas network increases costs for remaining customers as a shrinking customer base must pay for gas network maintenance. Those higher costs for remaining customers drive additional defections, and so on.[3]

While the model optimizes for system-wide costs (how much it costs overall), it does not optimize for potential distributional concerns (who pays those costs). Higher costs for remaining customers represents not only a potential accelerant of gas demand decline. It also represents an important equity challenge for policymakers, which we discuss further in *Section 3*.

3. *A recent study from the Brattle Group identified this dynamic as a major energy transition risk for gas utilities in the United States. They find that by 2040, given existing policies, electricity could replace 60 per cent of the heating demand currently being served by the gas sector in New York, increasing gas bills for remaining customers by 71 per cent (Graves et al. 2021). In the United Kingdom, their regulator noted a similar concern about the potential for spiralling network charges, with residual asset value (currently C$45 billion) paid for by fewer and fewer customers over time (Ofgem 2023). In February 2024, the energy regulator in France announced that gas rates will increase by 5.5 to 10.4 per cent in July 2024 to cover fixed costs amid declining gas consumption (franceinfo 2024).*

1.3 Implications for the gas system

The flipside of growing electricity demand and growing investments in the electricity system in the clean energy transition is falling gas demand. Gas demand from buildings declines on a cost-optimal pathway even with the availability of options such as biomethane, hydrogen, and hybrid heating systems. We consider implications for those decarbonization strategies below, as well as what declining gas demand means for the gas network.

Building heat is not a cost-effective use of low-emission gases

Biomethane and hydrogen are relatively scarce and expensive, and supplies are projected to remain limited.[4] Yet some sectors, such as heavy industry, will struggle to decarbonize without using them. In contrast, electricity is a simple and cost-effective option for building heating—meaning that it is more cost-effective for the economy as a whole to reserve their use for sectors where they provide the best value.

When cost-optimizing for the entire economy, the modelling results show biomethane and hydrogen are primarily used in other sectors, not for building heat. By 2050, Canada's buildings sector is using only 6 per cent of available hydrogen and 6 per cent of available biomethane. The rest is taken up in the industry, transportation, and energy production sectors (*see Figure H*).

4. *Hydrogen production cost assumptions in the NATEM model are derived from a range of studies, including IEA's* ***The Future of Hydrogen*** *report, Element Energy* ***Hydrogen Supply Chain Evidence Base, Data and Assumptions****, and various NREL datasets. Biomethane production cost assumptions were derived from IEA's* ***Outlook for biogas and biomethane report****, other literature, and consultations with stakeholder groups in this space.*

Feedstock constraints are an important limiting factor for biomethane production. Recent studies estimate that, given current feedstock availability and existing production technologies, Canada could feasibly produce between 90 and 218 petajoules of biomethane per year (*Abboud et al. 2010*; *Kelleher Environmental 2013*; *Stephen et al. 2020*). This is equivalent to only 2 to 5 per cent of Canada's total 2021 gas demand (*CER 2023*).

Early-stage technologies that produce synthetic gas from solid biomass could enable Canada to access forestry industry residues as feedstock; doing so would increase biomethane production potential by 150 petajoules, or 4 per cent of gas demand as of 2020. If active forest management techniques such as thinning are applied on Crown timberlands, this estimate could increase by several hundred petajoules (*Stephen et al. 2020*).

Even if the higher ranges of biomethane availability forecasts are realized, supplies available to the buildings sector will likely still be limited due to competing uses, such as heavy industry (*see Figure F*). Indeed, in the sensitivity analyses, tripling available biomethane feedstocks and reducing the cost of biomethane production by 30 per cent does not lead to an increased uptake of biomethane in the buildings sector. Instead, other sectors that are more difficult or more expensive to electrify use more biomethane.

The modelling results also suggest that biomethane feedstocks may be more efficiently used as direct fuel sources rather than converted into biomethane. When available biomethane feedstocks are tripled in the model, some of the additional feedstock is used to meet end-use energy demands directly; in particular, the buildings sector shows more than a fivefold increase in wood and wood-pellet fuel use in this scenario.

Global supply constraints make it unlikely that international trade will significantly increase Canada's domestic biomethane supply. The International Energy Agency estimates that if all current sustainable feedstocks for biomethane were used, they could serve just 20 per cent of current global gas demand (*IEA 2020*).

The use of hydrogen for building heat is constrained by cost and competition with other sectors.

In our modelling results, the vast majority of hydrogen is more cost-optimally used in sectors other than the buildings sector, such as heavy industry. On a cost-optimal pathway, we only see hydrogen boilers deployed in commercial buildings in Alberta, Manitoba, and Saskatchewan, at market shares of 15 per cent, 6 per cent, and 22 per cent, respectively. When we assume a halving managing peak demand may be overestimated, as NATEM and other models don't fully capture alternative strategies to mitigate the cost of peak demand, such as distributed energy resources and interprovincial trade.

By 2050, in our modelling results, hybrid heating systems burning low-emission gases are nearly the only context in which Canada's buildings are consuming gas—they make up the entirety of gas demand in the existing distribution system. Under a cost-optimal net zero pathway, all exclusively fossil-gas space heating is phased out by 2050.

Other approaches to peak shaving and load shifting could lower electricity capacity needs with less risk of locking in costly gas infrastructure.

So while hybrid heating systems maintain a role for gas networks, those networks are delivering very low volumes of fuel. The quantity of gas used for space heating in residential buildings still drops by 96 per cent, from an average of 4.7 GJ per month in 2020 to an average of 0.2 GJ per month in 2050. In commercial buildings, consumption drops 88 per cent, from an average of 122 GJ per month in 2020 to 15 GJ per month in 2050.

In Alberta, which sees the highest uptake of hybrid systems in 2050 (35 per cent of residential market share by 2050), residential gas consumption nonetheless plunges by 83 per cent over the same period (see Figure I). Even where buildings retain a gas furnace, heat pumps are covering most of the heating load.

As for commercial buildings, while hybrid systems rise to make up 50 per cent of national market share by 2050, gas consumption from commercial buildings still declines, falling by 91 per cent nationally by 2050.

All of this points to a future of profound upheaval for Canada's gas systems—even in regions where hybrid heat may play a significant role. Some buildings may still use gas for space heating in a net zero future, but only during the coldest days or weeks of the year. Gas utilities will find it complex and challenging to recover ongoing network maintenance costs from a customer base that is smaller and uses less gas.

Hybrid systems may appear optimal in some regions or contexts, but given the high costs of maintaining gas systems just to service peak demand, other approaches to peak shaving and load shifting could lower electricity capacity needs, with less risk of locking in costly gas infrastructure. As we discuss above, our modelling has limited representation of some of the newer peak shaving and load shifting options, so its findings for the cost-optimal levels of hybrid heating may be overestimated. In areas where hybrid systems could play a larger role, more granular modelling of regional pathways would help to better understand its costs and benefits compared to non-gas alternatives.

A larger role for hydrogen and biomethane comes with the risk of higher costs and reliance on less certain technologies

A cost-optimal pathway to net zero includes a modest role for some hydrogen and biomethane in building heat. A much larger role for low-emission gases in buildings is likely more expensive overall but could broaden the possibility of keeping existing gas infrastructure (furnaces in homes and pipelines in the ground) in use for longer. However, pushing for a bigger role for hydrogen and biomethane risks raising overall costs, and depends more on less-certain decarbonization technologies, while doing little to mitigate the need to invest in electricity capacity expansion.

To date, Canada's biomethane supply is fairly limited and expensive. In British Columbia, for example, ratepayers can elect to pay a premium of $7 per gigajoule for biomethane—about 30 per cent more than the price of fossil gas as of January 2024—to offset the emissions from their gas consumption. This price is below the actual additional cost to the gas utility, according to records provided to the regulator (*BCUC 2024*). Energir in Quebec also charges customers more for biomethane: as of October 2023, biomethane cost $19 per gigajoule compared to less than $3 per gigajoule for fossil gas.

Increased production capacity and importation are possible, at least in the near term. But given the feedstock constraints and competing uses we discuss above, a reliance on significant levels of biomethane for building heat could prove costly or difficult to deliver, which risks locking in higher costs to ratepayers, higher emissions, or both.

Blending hydrogen into existing gas supply systems risks under-delivering on greenhouse gas emissions reductions, unless utilities achieve much higher blending rates. Blends of five to 20 per cent by volume may require utilities investment and effort. But low-emission gases are at an earlier stage of their development, and their potential is less clear.

In any case, a larger role for low-emission gases in the buildings sector doesn't avoid the need to extensively build out electricity system capacity. Our modelling finds that using more of Canada's scarce supply of low-emission gases in the buildings sector requires greater electrification in other sectors, such as heavy transportation and industry, to meet emission targets. The required scale of the electricity system build-out ends up being similar.

Continued growth of the gas network is inconsistent with cost-effectively reaching net zero

Given the rapid shift away from gas consumption in buildings along a cost-optimal pathway to net zero (*see Figure H*), provinces that continue to expand their gas distribution networks could jeopardize Canada's climate goals or raise the cost of meeting them.

This conclusion is consistent with numerous other studies, including the following:

- In its report *Net Zero by 2050: A Roadmap for the Global Energy Sector*, the International Energy Agency concludes that, while gas pipelines will still have a role to play, additional investment in new gas pipelines is not indicated given the projected decline in fossil fuel demand (*IEA 2021*).

- In a 2022 analysis, the International Institute for Sustainable Development (IISD) found that declining fossil fuel demand may lead to stranded assets if utilities are unable to recover infrastructure expansion costs— leaving ratepayers or governments on the hook (*Cameron et al. 2022*).

- In a 2021 presentation, global research and consulting firm The Brattle Group asserted that accelerating electrification will increasingly disrupt conventional gas utility business models, and that companies will face increasing risks to recovering the capital investments they need to expand their networks (*Graves et al. 2021*).

2.2 The stakes of being off-track

This trend of continued expansion of gas systems while underinvesting in electricity systems presents risks for both ratepayer affordability and system reliability. If electricity systems do not grow fast enough, and gas networks continue to grow despite uncertainty about their long-term use, Canadian rate-payers face the risk of higher rates, reliability concerns, or both.

Continued gas network growth is creating risk by adding liabilities that must ultimately be paid for

Even as the clean energy transition continues apace, gas utilities are still laying pipelines and growing their distribution networks, despite the looming risk of a declining customer base as more consumers switch to electric heating technologies.

Gas utilities are still laying pipelines and growing their distribution networks, despite the looming risk of a declining customer base as more consumers switch to electric heating technologies.

Because companies amortize their infrastructure investments over decades, infrastructure decisions taken today will affect affordability for consumers now and for decades to come. The broad base of gas customers typically subsidizes new connections to existing gas networks, assuming existing customers will benefit from sharing the fixed costs of the gas network across a larger base. But this only benefits all gas customers so long as the gas customer base keeps growing and new customers continue to use gas for decades after connecting.

For many new connections, the cost is covered by gas ratepayers if the anticipated revenue from the new customer over a given time period (typically, 40 years) is equal to or greater than the cost of connecting them to the gas network and serving them over that time. The cost accounting typically assumes the new customer will stay connected to the system for the full time period. When gas utilities extend their networks into rural regions, however, projected new customer revenue—even when assumed to last over 40 years—will only cover a small part of costs. Direct government support for network expansion has enabled rural expansion in some provinces (for example, Ontario, Alberta, Saskatchewan), where otherwise connections would be uneconomic.

Under these arrangements, there is little incentive for a developer to choose electrification, even where the electric option would be cheaper for the eventual building occupants, since the cost of gas connection is free to the developer and the energy bills are paid by the occupants. But this choice exacerbates risks for gas customers. Should these new customers use less gas than anticipated (for example, by installing a hybrid system down the road) or leave the network before the end of the 40 years' anticipated revenue from their bills, the remaining customer base could be left covering the remaining cost of connecting them to the network through higher rates.

Ongoing network expansion presents significant risk to all provinces with gas systems.

As our analysis in *Section 1* shows, falling gas demand is part of a cost-optimal net zero pathway across all sensitivity analyses. A declining number of gas customers will strain a given gas utility's ability to recover the costs of its historical and ongoing infrastructure investment. This risk of stranded assets is most acute for new investments in infrastructure, such as pipeline replacements and expansions. Newer infrastructure has less accumulated depreciation. Its higher remaining asset values relative to older infrastructure represent higher liabilities for current and future customers to bear, should the assets become stranded due to disuse or underuse before the end of their expected lifetime.

Ongoing network expansion presents significant risk to all provinces with gas systems. However, the extent and age of infrastructure, like the prevalence of gas heating, is highly variable by region. Provinces with newer or recently replaced or expanded systems face higher risks to customer bills as more infrastructure has yet to be paid off. And those provinces with a small user base face an elevated risk that these liabilities will land heavily on remaining customers if and when assets end up stranded. Risks can therefore be especially pronounced for provinces with smaller and newer gas networks, such as New Brunswick and Nova Scotia.

3.3 Why status quo inertia puts the energy transition at risk

The limitations of climate policy and utility regulation discussed above interact to sustain a status quo trajectory for building heat that does not align with a cost-optimal path to net zero. It points instead to rising greenhouse gas emissions, growing gas networks, and electricity systems that aren't growing fast enough.

Gas utility business models are predicated on network expansion

Gas utilities' existing business models and current regulatory structures mean that their incentives can be at odds with maintaining future bill affordability for consumers in the context of the energy transition. Because gas utilities realize returns based on the infrastructure they install rather than the fuel they sell, they have a direct economic incentive to pursue continued growth of gas infrastructure and new customers—even if the long-term usage case is uncertain.

In the regulated segments of their business, gas utilities are largely insulated from most market signals—including the prospect of declining gas demand. A gas utility will pass some of its costs—including the cost of the gas itself, and carbon price costs—straight through to its customers. The gas utility's profits do not depend directly on gas sales volumes. As long as a gas utility's distribution networks remain in place, customers remain connected to them, and the gas utility can still recover its fixed costs through rates, a decline in sold gas volume—for example, from some customers converting to hybrid heat—is not an immediate threat to the underlying business model.

A gas utility earns its profits via a predetermined rate of return on its infrastructure investments as approved by the regulator. To secure approval, utilities must convince the regulator that new infrastructure will be necessary and useful. But once infrastructure is approved, utilities can be reasonably assured they will earn a return on it even if that usage case does not bear out.

The regulator can serve as a check against the accrual of excessive liabilities in the form of infrastructure that does not prove sufficiently used and useful over its lifetime. But regulators are not only required to protect customers from rate increases; they must also protect utilities' ability to maintain an adequate business and support the level of investment that is required for continued provision of energy services. They must also provide the opportunity for gas utilities to earn a reasonable rate of return, and can only stop or delay adding new investment to customer bills if such investment is shown to be imprudent—for example, if it will be underused or is more expensive than an alternative. As we discuss above, regulators are often constrained in their ability to make these kinds of assessments in the context of the energy transition.

In a less regulated sector, market signals would reduce the incentive that companies would have to pursue a strategy of continued network expansion in the face of potential demand declines.

In a less regulated sector, market signals would reduce the incentive that companies would have to pursue a strategy of continued network expansion in the face of potential demand declines. But gas utilities are partially insulated from these kinds of signals. They therefore have a strong incentive to advocate for pathways that require ongoing system maintenance or expansion—such as hybrid heating or a shift towards low-emission gases.

Fewer new customers and a declining customer base in the future is the primary concern for gas utilities under their current business model, but falling gas demand in terms of total volume does create some challenges under existing gas rate design. Historically, fixed costs have been partly included in variable consumer charges for reasons of consumer preference and to avoid a regressive pricing model that disproportionately affects lower-income consumers. With declining gas usage, however, gas utilities will eventually need to seek approval to modify their rate structures or seek public subsidies to recover the costs of increasingly underutilized assets.

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

DECISION AND ORDER

EB-2022-0200

ENBRIDGE GAS INC.

Enbridge Gas Inc. Application for 2024 Rates – Phase 1

BEFORE: **Patrick Moran**
Presiding Commissioner

Emad Elsayed
Commissioner

Allison Duff
Commissioner

December 21, 2023

Some parties (APPrO, CCC[33], Energy Probe and LPMA) indicated that the energy transition issues should be re-examined once additional provincial policy direction, such as the Ontario government's response to the EETP report, on the energy transition has been provided. SEC noted that government policies will change many times over the lives of the assets that Enbridge Gas is investing in today, and submitted that if there is no government-mandated path to net zero, that does not mean that the status quo is the appropriate planning assumption.[34]

Procedurally, some parties (APPrO, GFN, LPMA and Three Fires Group) expressed a preference for considering the energy transition issues in the context of a generic hearing, likely involving the electricity sector as well, and potentially others with an interest in the energy transition issues, such as providers of other energy services, municipalities, and Indigenous communities.

Several other parties were of the view that the energy transition can be further considered in future Enbridge Gas applications, not a generic hearing, but that the next major Energy Transition Plan update (and review by the OEB) should likely not wait five years until Enbridge Gas's next scheduled rebasing. While recognizing that the rate term is intended to be addressed in Phase 2 of this proceeding, CCC, GEC and IGUA submitted that due to energy transition considerations, a shorter rate term may be more appropriate. SEC expressed a preference for a "planning pause" where timing of future steps on the energy transition is at Enbridge Gas's discretion. Under this proposed approach, rate base would be held steady at its current level for the time being (capital in-service additions equal to depreciation), but Enbridge Gas could apply to rebase at any time, once it has filed a more detailed Energy Transition Plan including an options analysis.

Enbridge Gas did not support the OEB convening a generic proceeding on the energy transition in advance of the next rebasing application, stating that this would likely not be as efficient or effective as a more business-led planning process.

Findings

The OEB concludes that Enbridge Gas's proposal is not responsive to the energy transition and increases the risk of stranded or underutilized assets, a risk that must be mitigated. In particular, Enbridge Gas has not met the onus to demonstrate that its

[33] CCC submitted that Enbridge Gas should be required to start analysis along the lines of that proposed by Dr. Hopkins and Energy Futures Group now, but that the ability to complete this analysis would be enhanced once the Government of Ontario's policy objectives were clearer.
[34] SEC Submission, p.11.

leading to a continuing financial decline for the utility, often referred to as the utility death spiral.

In the face of the energy transition, Enbridge Gas bears the onus to demonstrate that its proposed capital spending plan, reflected in its Asset Management Plan, is prudent, having accounted appropriately for the risk arising from the energy transition.

The record is clear that Enbridge Gas has failed to do so. Enbridge Gas has taken the position that there is no stranded asset risk for the purposes of setting rates for 2024. This is not logical. The capital expansion proposed by Enbridge Gas for 2024 amounts to $1.47 billion and forms the basis for its proposed five-year rate term, with 2024 rates being adjusted annually for inflation, which would include a continuation of capital at a similar pace beyond 2024. This five-year period is part of the ten-year period covered by Enbridge Gas's Asset Management Plan, which contemplates a total capital expenditure of $14 billion over ten years. Based on Enbridge Gas's proposal, the depreciation expense for these assets would be recovered over 40 years or more,[36] with no meaningful consideration of:

- Ontario's policy objective to reduce greenhouse gas emissions by 30% below 2005 levels by 2030, which is seven years away;
- Canada's policy objective to achieve net zero carbon emissions by 2050, which is 27 years away, and
- The risk of assets becoming stranded or underutilized.

In light of this, the position taken by Enbridge Gas that there is no stranded asset risk in 2024 cannot stand. The assets Enbridge Gas proposes to add to rate base in 2024 would be depreciated over the next 40 years or more,[37] based on the physical asset life. The same would apply to the assets that Enbridge Gas plans to add in each of the following four years, as proposed in its application, and over the next ten years, as proposed in its Asset Management Plan. It is the 40-year horizon against which the stranded asset risk must be examined, not the five-year horizon of the requested rate term that Enbridge Gas urges the OEB to use.[38] When looked at through the 40-year lens, what Enbridge Gas proposes looks very much like business as usual and it is not sustainable.

[36] Exhibit J13.6.
[37] Exhibit J13.6.
[38] Enbridge Gas, Argument-in-Chief, p. 166.

customers would need to pay under different revenue horizons, and the corresponding reduction in Enbridge Gas's customer connections capital budget (Table 1). Relative to a 40-year revenue horizon, the impact would range from an average CIAC of $645 and five-year capital budget reduction of $124 million using a 30-year revenue horizon, to an average CIAC of $4,428 and a five-year capital budget reduction of $853 million using a ten-year revenue horizon.

Table 1
Customer Connections Capital Expenditure Supported by Different Revenue Horizons[87]

Line No.	Revenue Horizon	2024	2025	2026	2027	2028	Total	Reduction vs. 40 Year Revenue Horizon	CIAC per Customer
	(Years)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	
1	40	304	248	258	254	250	1,314		
2	30	229	227	239	241	253	1,190	124	645
3	25	210	208	219	221	235	1,094	220	1,140
4	20	188	185	196	198	205	972	342	1,774
5	15	146	144	153	154	159	757	557	2,890
6	10	89	88	93	95	96	460	853	4,428

Findings

Given that the new revenue horizon only applies to projects connecting on or after January 1, 2025, there is no impact to the 2024 capital budget. However, there will be an impact in 2025 and subsequent years that needs to be considered. The OEB is of the view that this is best addressed in Phase 2 of this proceeding, which will also consider the issue of incentive ratemaking mechanisms in the context of the energy transition.

Under the new revenue horizon, any developer that wants to include gas servicing will need to pay the full connection cost upfront. Regardless of whether a developer chooses to proceed with gas service and make the CIAC payment or chooses to avoid the cost and go with all electric servicing, there will be an impact to the capital budget in 2025. As part of the updated evidence that Enbridge Gas plans to file for Phase 2, the OEB directs Enbridge Gas to address how the reduction will be implemented during the proposed IRM term.

[87] Exhibit J11.1, Table 1. Connection costs associated with the Natural Gas Expansion Program projects are not included in this table.

- The proposed capital expenditures for 2024 do not reflect the risk associated with the energy transition, more specifically the longer-term risk of under-utilized or stranded assets. The energy transition risk is not even explicitly mentioned in Enbridge Gas's corporate risk register.

- The proposed 2024 capital expenditure represents a significant increase compared to average historical spending. The average annual spending during the 2018 to 2022 period is $1,148.2 million. The proposed updated 2024 spending ($1,470.3 million) is $322.1 million (28%) higher than the 2018 to 2022 average actual spending. The approved 2024 capital expenditure in this proceeding ($1,220.3 million) is still higher than the average actual spending for the 2018 to 2022 period. In its evidence, Enbridge Gas considered $1.2 billion as a minimum constraint to safely operate and maintain the natural gas system, respond to demand growth, invest in low-carbon solutions and ensure on-going reliability and service to customers.[96]

- Enbridge Gas's Asset Management Plan projection for the period 2021 to 2025 in the current application ($7,235.1 million)[97] is significantly higher than the previous Asset Management Plan projection for the same period in the 2021 rate application ($6,297.2 million); an increase of $937.9 million or 14.9%.

The OEB's reduction of $250 million is an envelope reduction to the 2024 capital program and does not specify which projects are to be deferred or reduced to achieve that envelope reduction. Enbridge Gas has sufficient flexibility to re-prioritize its capital projects within its Asset Management Plan based on risk to accommodate the 2024 reduction and flatten the level of expenditure for future years. The OEB is reducing the system renewal budget envelope to motivate Enbridge Gas to improve its approach to integrity management, repair and life extension, so that only truly necessary replacement projects proceed.

Enbridge Gas is directed, in its next rebasing application, to file an Asset Management Plan that provides clear linkages between capital spending and the energy transition risk. The Asset Management Plan should address scenarios associated with the risk of under-utilized or stranded assets and possible mitigating measures. As discussed later in this Decision and Order, Enbridge Gas will also be required to determine whether to propose changes to its approach to depreciation to account for the impact of the energy transition, recognizing that a failure to act prudently in relation to the risk of stranded assets will have an impact on the ability to keep those assets in rate base.

[96] Exhibit 2, Tab 5, Schedule 1, p. 6.
[97] As per Exhibits J13.14 and J14.5.

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

DECISION AND ORDER

EB-2021-0002

ENBRIDGE GAS INC.

Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027)

BEFORE: **Michael Janigan**
Presiding Commissioner

Anthony Zlahtic
Commissioner

Patrick Moran
Commissioner

November 15, 2022

7. It is important that Enbridge Gas's DSM programs result in more meaningful reductions in overall natural gas sales volumes. The OEB has introduced a new component to the shareholder incentive structure that provides an incentive to Enbridge Gas to deliver more benefits to customers, primarily through greater levels of natural gas savings, consistent with broader government policy. Enbridge Gas will be eligible to earn an additional $30 million shareholder incentive through the new End-of-Term Natural Gas Reduction Incentive. This incentive is incremental to the incentive for achieving the program scorecard targets. To be eligible to earn the End-of-Term Natural Gas Reduction Incentive, Enbridge Gas must achieve a total reduction in weather normalized annual natural gas sales volumes of 1.5% over the three-year term.
8. The OEB approves a revised Natural Gas DSM Framework as set out in Schedule E.

The OEB considered comments and recommendations from stakeholders related to including more opportunities for customers to electrify. The OEB has approved incentives for measures, such as cold climate electric heat pumps that allow existing gas customers to switch away from gas. The OEB has also removed the requirement for program participants to continue to be gas customers as a condition of participating in DSM programming. The OEB is of the view that requiring program participants to remain a natural gas customer after completing an efficiency project is inconsistent with allowing customers to make their own energy use decisions. Further, requiring a program participant to continue to use natural gas acts as a barrier to achieving greater overall natural gas savings and greenhouse gas reductions. The OEB's modifications will enable customers the ability to assess the best energy options for their household in order to maximize energy efficiency improvements, reduce their natural gas bill and help avoid incremental greenhouse gas emissions. The OEB will not issue any policy direction beyond these measures at this time.

The OEB is aware that the Government of Ontario appointed an Electrification and Energy Transition Panel on April 22, 2022 to provide advice to the Minister of Energy on various issues related to integrated long-term energy planning in Ontario.[3] The OEB is of the view that further direction and any mandate to electrify the energy system, or portions of it, will be developed with the necessary stakeholders, including the Government of Ontario and the Independent Electricity System Operator (IESO). Once the central policy is developed, further action can be taken to ensure all conservation

[3] https://www.ontario.ca/orders-in-council/oc-6982022

electric options can be advanced, customers may feel misled about the expected savings and comfort they could receive if the all-electric solution proves inadequate for effectively meeting their heating needs.

Finally, Enbridge Gas noted that it expects that natural gas heat pumps will have a future in Ontario and will become cost-effective. Enbridge Gas submitted that there is no basis nor logical argument which supports the exclusion of natural gas heat pumps from consideration by gas customers as part of a DSM program. Enbridge Gas also noted that this is true of the recommendations to require it to provide incentives for non-gas customers or incentives to current gas customers so that they may leave the system.

Findings

The OEB does not approve the Low Carbon Transition Program. The OEB finds that focusing efforts on gas heat pumps, a technology that is not currently commercially available nor as cost-effective as electric heat pumps is not prudent. Although gas-fired heat pumps may be more efficient than high efficiency gas furnaces, offering incentives for this measure would continue the use of natural gas and associated GHG emissions well into the future.

The OEB is of the view that it is more effective to re-allocate the entire Low Carbon Transition Program budget to the Residential Whole Home program offering so that greater progress can be made in advancing the use of electric heat pump technologies throughout Ontario.

4.2.9 Issue 10h – Other Programs

The OEB's Issues List also asked if any other programs should be included in addition to or to replace those proposed by Enbridge Gas.

Summary of Positions

There were some additional program opportunities suggested by parties, including OEB staff's expert witness, Optimal Energy Inc., and Pollution Probe.

Optimal Energy suggested that Enbridge Gas consider a retro-commissioning offering and an Energy Manager Subsidy offering as two potential additional offerings as part of the Commercial Program. Enbridge Gas noted that its experience with similar retro-commissioning offerings, including the Strategic Energy Management program, have not proven to be cost-effective. Enbridge Gas noted that if it were to propose any additional offerings or measures, it would also require additional budget amounts to do so, which is difficult in a constrained environment.

Gas Reduction Incentive to motivate Enbridge Gas to focus on greater natural gas savings levels throughout the term of the new DSM plan.

4.7 Research and Development Activities – Issue 11

Enbridge Gas proposed an annual research and development budget of $3.23 million. Of this amount, approximately $2.6 million is budgeted for the research and innovation fund (RIF). Enbridge Gas proposed that the research and development budget increase by inflation in subsequent years. Enbridge Gas indicated that it will use the RIF to investigate new measures and innovative program designs to address local DSM market needs, develop emerging technologies through lab testing and market research, implement pilot programs to test new program concepts or modifications, and conduct research to more consistently and accurately estimate natural gas savings generated through DSM programs.

Summary of Positions

Parties were generally supportive of the continuation for Enbridge Gas's proposed research and development budget. However, OEB staff noted that these kinds of activities should be undertaken with a clear intention for application in its DSM plan. OEB staff also recommended that in addition to oversight by the SAG, Enbridge Gas should provide a similar summary of research and development projects as part of its DSM Annual Report beginning with the 2022 DSM Annual Report that will be assembled in early 2023. This will allow the OEB and interested stakeholders to follow along more closely and be able to seek further information from Enbridge Gas. Enbridge Gas responded arguing that including the SAG as part of its research and development activities will delay the onset of the activities and increase costs and in the end, not add value.

OEB staff and GEC also argued that, primarily due to the important policies in place to reduce GHG emissions, that it is inappropriate to continue using research and development funds on gas-fired measures where electric alternatives exist. Enbridge Gas responded noting that the current realities are that there remains such a large demand for natural gas and gas appliances in Ontario. Therefore, restricting opportunities to improve gas usage efficiency is surprising and not appropriate.

Findings

The OEB approves the proposed research and development costs, including the RIF. However, the OEB agrees with parties that suggested that research and development funding not be expended on natural gas-fired measures where there are electric alternatives, such as heat pumps. The OEB expects that Enbridge Gas will, at a minimum, share its research and development plan with the SAG for comment. This will provide all stakeholders with an opportunity to understand the benefits of the activities contemplated by Enbridge Gas. However, ultimately, Enbridge Gas is responsible for proving the value of how it has expended ratepayer funding. This includes reporting on research and development activities as part of its DSM Annual Report. It also includes supporting its annual application for approval to dispose of amounts in its DSM deferral and variance accounts.

4.8 Evaluation, Measurement & Verification – Issue 12

The OEB-led evaluation process began in 2015 following the OEB assuming responsibility of the evaluation of DSM program results from the legacy natural gas utilities. The central evaluation function carried out during the 2015-2020 term is called impact evaluation – a process to verify the results of the various programs that have been delivered the previous year. To support the OEB's efforts, it has hired an expert third party consultant to act as the OEB's Evaluation Contractor (EC) and formed an Evaluation Advisory Committee (EAC) that is chaired by OEB staff and includes representatives from Enbridge Gas, expert stakeholders, and staff from the IESO. The EAC provides input to the EC on evaluation activities, including broad evaluation plans and specific work projects.

Enbridge Gas proposed several items related to the evaluation, measurement and verification (EM&V) of approved DSM programs. The requests are summarized below:

1. Approval of Enbridge Gas's proposed Terms of Reference (ToR) for the EAC.
2. Approval of Enbridge Gas's gross savings measurement methodologies and consistent use by the OEB's EC when verifying program results.
3. Direction from the OEB to OEB staff to develop a natural gas DSM-specific DSM EM&V Protocols document by December 31, 2022. Enbridge Gas argued that Ontario DSM evaluation protocols would: (i) provide clarity on how and which evaluation methodologies are used in Ontario to support program design and delivery efforts, (ii) ensure EC's are effectively and appropriately executing evaluation activities, (iii) ensure interested parties are engaged and (iv) publicly document Ontario's DSM evaluation protocols.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 10, Tab 1, Schedule 7

Preamble:

The following image is from a recent Enbridge ad:

Question(s):

a) Please confirm that this incentive is being funded by Enbridge Gas's Technology Development team. What are the functions of that team and what is its budget?

b) Would the ETTF undertake similar activities related to gas heat pumps? Would the ETTF be run by the Technology Development team?

c) What is the budget for these gas heat pump incentives and how are they funded? Please provide a breakdown by year and between incentive costs and administration costs (e.g. promotion, etc.).

d) If ratepayer funds are being used for this initiative, please justify how that is allowed in light of the OEB denying Enbridge approval to spend ratepayer funds on gas heat pumps in the most recent DSM proceeding.

Response:

a) Confirmed. As outlined in response at Exhibit I.1.10-PP-12, part c), the Technology Development team leads the low-carbon technology development work with the goal of advancing customer focused low-carbon solutions by supporting, evaluating, developing and implementing low-carbon technologies. The team's budget varies based on the initiatives supported in any given year. As detailed in response at Exhibit I.1.10-PP-8, part b) subpart ii), the Technology Development team has funded approximately $8 million, through O&M, in various technology innovation projects in the last seven years from 2017 to 2023.

b) Yes. Please see response at Exhibit I.1.10-ED-13 for additional examples. Further details on the wide range of low-carbon technology development initiatives and activities that the ETTF will fund are outlined at Phase 2 Exhibit 1, Tab 10, Schedule 7, page 4, Section 2.

   Yes, the ETTF would be run by the Technology Development team.

c) This pilot is funded within Enbridge Gas's O&M budget. The planned budget breakdown is:

Table 1
2024 Budget

Pilot Program Activity	2024 Budget
Customer Incentive	$500,000
2-year Extended Warranty	$100,000
Marketing & Program Administration	$70,000
Pilot Evaluation	$20,000
Program total	$690,000

d) This program is planned to run for the 2024/2025 heating season and the 2025 program budget is yet to be determined.

In the Decision and Order, the OEB directed that "research and development funding not be expended on natural gas-fired measures where there are electric alternatives, such as heat pumps".[1] Enbridge Gas interprets this decision to be specific to the research and innovation funding requested in the DSM application for DSM initiatives, and believes it is appropriate to fund technology development initiatives for gas fired equipment outside of the DSM Plan/funding, including gas heat pumps, when the gas fired equipment can provide benefits beyond energy efficiency such as:

- Maintaining consumer choice via supporting the development and commercial availability of higher efficient gas equipment for consumers wanting to maintain their gas space and water heating, and who are looking to use highly efficient gas equipment;
- Reducing GHG emissions via supporting the development and commercial availability of gas equipment that can use low-carbon fuels; and
- Reducing gas peak load via supporting the development and commercial availability of gas equipment that is increasingly more efficient at peak design temperatures, which can support the delay, downsize or avoidance of new facility infrastructure. This could become increasingly important in areas where the electricity system is constrained.

[1] EB-2021-0002, OEB Decision and Order, Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027), November 15, 2022, p.77.

environmental defence
INSPIRING CHANGE

June 19, 2023

Josephine Palumbo
Deputy Commissioner, Deceptive Marketing Practices
Competition Bureau
Place du Portage I
50 Victoria Street, Room C-114
Gatineau, Quebec K1A 0C9
Josephine.Palumbo@canada.ca

Dear Ms. Palumbo,

Re: Enbridge Gas Deceptive Marketing Practices

We are writing to request that the Commissioner of Competition commence an inquiry into deceptive marketing practices by Enbridge Gas Inc. ("Enbridge") under s. 9 of the *Competition Act*. As detailed below, Enbridge is misleading consumers into connecting to its gas system using false and misleading representations contrary to sections 52 and 74.01 of the *Competition Act*. Enbridge is telling potential customers that gas is the most cost-effective way to heat their homes and suggesting that it is "clean energy" and "low carbon." None of these representations are true.

These representations are causing real harm. Customers in gas expansion areas stand to lose approximately $20,000 on average if they switch to gas instead of installing a high-efficiency electric heat pump (over the lifetime of the equipment).[1] This will also create far more carbon pollution, making it more difficult and expensive to reach federal climate targets.

We also request temporary orders to stop Enbridge from deceiving potential customers while the proceeding progresses. Enbridge is making these false and misleading representations on an ongoing basis. With each week that passes, more customers sign up to convert their heating to gas instead of purchasing a high-efficiency electric heat pump resulting in unnecessarily high energy costs and carbon pollution to the detriment of consumers, competition, and the climate.

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[1] Dr. Heather McDiarmid, *An Analysis of the Financial and Climate Benefits of Electrifying Ontario's Gas-Heated Homes by Installing Air-Source Heat Pumps*, August 2, 2022, p. 11 (link); For the difference in costs with the latest gas prices, see Ontario Clean Air Alliance, *Heat Pump Calculator for New Gas Communities* (link); see also Evidence of the Energy Futures Group in Ontario Energy Board File # EB-2022-0200, p. 23 (link). The actual savings depend on a variety of factors. See pages 5 and 6 for examples.

Background

Enbridge Inc. and Methane Gas

Enbridge owns nearly all of the methane gas distribution pipelines in Ontario. Methane gas is commonly known as "natural gas". However, methane gas is a potent greenhouse gas that pollutes the environment and causes climate change when it is burned and when it leaks from hydraulic fracturing extraction sites, pipelines, storage facilities, and customer equipment. The combustion of methane gas alone is responsible for approximately one-third of Ontario's greenhouse gas emissions.[2] Heating homes and businesses with gas accounts for approximately 19% of Ontario's green house gas emissions.[3]

In Ontario, Enbridge earns profit by investing in gas pipelines. It therefore has a strong financial interest in encouraging Ontario homes and businesses to switch to gas and remain with gas. The more capital that needs to be invested in pipelines, the more Enbridge stands to earn in profit. Enbridge also has a strong financial interest in gaining and keeping customers to pay for the pipelines it has already built through gas distribution charges that are levied on all customers on their gas bills.

Enbridge has no real competition when it comes to the distribution of gas in Ontario.[4] Due to a past market consolidation, Enbridge serves over 99.7% of all gas customers in the province.[5]

Enbridge's main competitors in Ontario are in fact electricity distribution companies. Most of these electricity distribution companies are owned by municipalities, like Toronto Hydro or Hydro Ottawa. The biggest threat to Enbridge's business is that its customers convert from gas heating to high-efficiency electric cold climate heat pumps. Another threat is that customers with expensive oil heating decide to switch to electric heat pumps instead of gas.

Enbridge has an additional interest in gaining and keeping gas customers in Ontario because it and its parent and sister companies own many of the large gas transmission pipes that bring gas to Ontario and move it between regions within

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[2] Enbridge Evidence in Ontario Energy Board File #EB-2022-0200, Exhibit 1, Tab 10, Schedule 3, Page 2 (link).
[3] Dr. Heather McDiarmid, *An Analysis of the Financial and Climate Benefits of Electrifying Ontario's Gas-Heated Homes by Installing Air-Source Heat Pumps*, August 2, 2022, p. 8 (link).
[4] Gas distribution pipelines are a natural monopoly. Each gas distribution company has a monopoly in the area it serves.
[5] Ontario Energy Board, Yearbook of Natural Gas Distributors, 2021/22, p. 15 (link).

Ontario. If gas demand stops growing or falls, Enbridge and its parent and sister companies could lose revenue.

The Context: Gas Expansion Communities

The deceptive marketing in this case was (and continues to be) directed to customers in gas expansion communities. These are small existing communities that Enbridge is adding to its gas system through a government program.[6] Like everywhere else in its system, Enbridge has an interest in signing up new customers in these communities, to help to trigger "upstream" capital investments that Enbridge profits from. New customers also help to generate the revenue needed to pay for existing infrastructure.

Enbridge has a particularly strong interest in signing up new customers in these gas expansion communities because it is required to maintain a "ten-year rate stability period" for each project.[7] That means that Enbridge bears the financial risk for that ten-year period that too few customers connect to the new pipeline to pay for it.[8]

The Competition: High-Efficiency Cold Climate Heat Pumps

For a long time, methane gas was the cheapest way to heat homes. However, electric cold climate heat pumps are now much cheaper than gas for consumers.[9] Annual costs are lower because heat pumps are approximately three times more efficient than gas furnaces (or five times for ground-source heat pumps, also known as geothermal) and because customers can avoid paying monthly charges to Enbridge for use of its gas system.[10] Upfront equipment costs are also often lower because heat pumps provide both heating and cooling in one unit and because of federal rebates.

Heat pumps are so efficient because they *move* heat instead of *converting* gas or electricity into heat. Standard gas and electric heating cannot surpass 100% efficiency, whereas heat pumps can be multiple times more efficient – they can use 1 kW of electricity to move 3 kW of heat (or more) indoors. They can do this even

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[6] For background on the program, see: Globe and Mail, *Ontario increasing reliance on natural gas as others move away from fossil fuels*, June 11, 2021 (link).
[7] Ontario Energy Board, Letter Re Potential Projects to Expand Access to Natural Gas Distribution, March 5, 2020. p. 7-8 (link).
[8] *Ibid*.
[9] Evidence of the Energy Futures Group in Ontario Energy Board File # EB-2022-0200, p. 23 (link); Dr. Heather McDiarmid, *An Analysis of the Financial and Climate Benefits of Electrifying Ontario's Gas-Heated Homes by Installing Air-Source Heat Pumps*, August 2, 2022, p. 11 (link); For the difference in costs with the latest gas prices, see Ontario Clean Air Alliance, *Heat Pump Calculator for New Gas Communities*, (link).
[10] National Resources Canada, *Heating and Cooling With a Heat Pump*, (link).

in cold temperatures because, counterintuitively, there is still a great deal of heat energy in very cold air.[11]

Customers are very vulnerable to deceptive advertising about the benefits of gas heating because most are not aware of heat pumps or the advancements that have been made in heat pumps in recent years. Recent changes that have made heat pumps less expensive than gas heating include the following:

- The efficiency of heat pumps has been increasing with advancements such as variable speed compressors.[12] Units available in Canada are up to 380% efficient even in cold areas like Ottawa (and more for ground source heat pumps).[13] More efficient units are cheaper to operate because they use less electricity.

- Heat pumps are now able to provide heating in Ontario's cold winters.[14]

- Canada's steadily increasing price on carbon pollution makes gas heating more and more expensive every year vis-à-vis electrical heating. By 2030, the carbon pollution price on gas will equal 32.40 cents/m^3.[15] By comparison, that amounts to over *three times* the price charged by Enbridge for methane gas in Toronto in January of 2020 (10.19 cents/m^3).[16]

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[11] National Resources Canada, *Heating and Cooling With a Heat Pump*, (link) ("It may be surprising to know that even when outdoor temperatures are cold, a good deal of energy is still available that can be extracted and delivered to the building. For example, the heat content of air at -18°C equates to 85% of the heat contained at 21°C. This allows the heat pump to provide a good deal of heating, even during colder weather.")
[12] Enbridge Gas, Federal Carbon Charge (link).
[13] National Resources Canada, Heating and Cooling With a Heat Pump (link). National Resources Canada notes: "On a seasonal basis, the heating seasonal performance factor (HSPF) of market available units can vary from 7.1 to 13.2 (Region V). It is important to note that these HSPF estimates are for an area with a climate similar to Ottawa. Actual savings are highly dependant on the location of your heat pump installation." Most Ontarians live south of Ottawa. The conversion factor between HSPF and a seasonal Co-Efficient of Performance (sCOP) is HSPF*0.293. An HSPF of 13.2 amounts to an sCOP of 3.8676, which equates to the heat energy output from the unit being 386% of the electrical energy input into the unit.
[14] National Resources Canada, *Heating and Cooling With a Heat Pump*, (link) ("More recently, air-source heat pumps that are better adapted to operating in the cold Canadian climate have been introduced to the market. These systems, often called cold climate heat pumps, combine variable capacity compressors with improved heat exchanger designs and controls to maximize heating capacity at colder air temperatures, while maintaining high efficiencies during milder conditions.").
[15] Enbridge, *Federal Carbon Charge* (link).
[16] Ontario Energy Board, *Historical Natural Gas Rates* (link).

- The federal government is now providing $5,000 incentives for customers to switch to high-efficiency electric heat pumps as part of its Greener Homes Grant.[17]

- The federal government is now providing an *additional* $5,000 in incentives for customers to switch from oil to high-efficiency electric heat pumps if they earn a median income or lower (e.g. $122,000 after-tax income for a family of 4 in Ontario) through the Oil to Heat Pump Affordability Program.[18]

- The federal government is now providing up to $40,000 in interest free loans, which can be put towards conversions to electric heat pumps, and not gas equipment, through the Greener Homes Loan.[19]

A typical homeowner in a gas expansion community would save approximately $20,000 with an electric heat pump versus gas heating over the lifetime of their heating equipment.[20] These savings mainly come from lower ongoing heating costs and cooling costs, which arise because electric heat pumps are more efficient at heating and cooling in comparison to traditional gas equipment paired with an air conditioner. As noted above, savings can also arise from lesser upfront costs. The $20,000 savings figure does not incorporate the benefit from interest-free financing available for heat pumps or the new $5,000 oil to heat pump incentive.

The actual savings will fluctuate depending on building characteristics, energy prices, and assumptions such as equipment costs. For instance, the savings from heat pumps will decline if, for example, gas prices drop or if a customer requires an upgrade to their electrical panel for the heat pump (which costs approximately $2,000).[21] On the other hand, savings from heat pumps will increase if gas prices increase, a house is heated with electric baseboards (because gas heating requires approximately $7,000 to add ducts whereas heat pumps can be installed without ducts),[22] or a customer with oil heating is eligible for $10,000 in federal rebates.[23] An expert analysis conducted by the Energy Futures Group found that heat pumps are still cheaper on a full lifetime basis even if various assumptions are adjusted to

[17] Government of Canada, *Canada Greener Homes* Grant (link).
[18] Government of Canada, *Oil to Heat Pump Affordability Program* (link).
[19] Government of Canada, *Canada Greener Homes Loan* (link).
[20] Dr. Heather McDiarmid, *An Analysis of the Financial and Climate Benefits of Electrifying Ontario's Gas-Heated Homes by Installing Air-Source Heat Pumps*, August 2, 2022, p. 11 (link); For the difference in costs with the latest gas prices, see Ontario Clean Air Alliance, *Heat Pump Calculator for New Gas Communities*, link; see also Evidence of the Energy Futures Group in Ontario Energy Board File # EB-2022-0200, p. 23 (link).
[21] Evidence of the Energy Futures Group in Ontario Energy Board File # EB-2022-0200, p. 24 (link).
[22] Enbridge, *Response to Board Staff Interrogatory 4 in EB-2022-0249*, Exhibit I.STAFF.4 (link, pdf page 23).
[23] Government of Canada, *Oil to Heat Pump Affordability Program* (link); Government of Canada, *Canada Greener Homes* Grant (link).

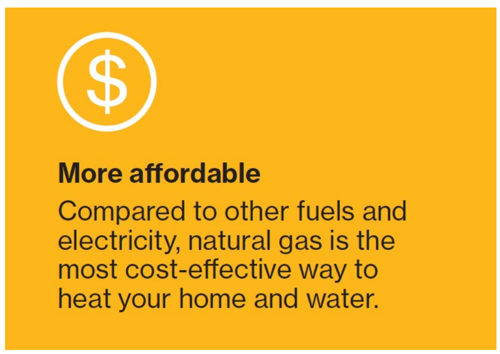
favour gas heating even outside community expansion areas where the 23 cents/m^3 surcharge applies.[24]

False and misleading representations

Enbridge is misleading customers into connecting to its gas system through deceptive marketing. These representations are being made in materials sent by mail, delivered at the doorstep, and posted at community events. A full package of these materials is attached. They are discussed below.

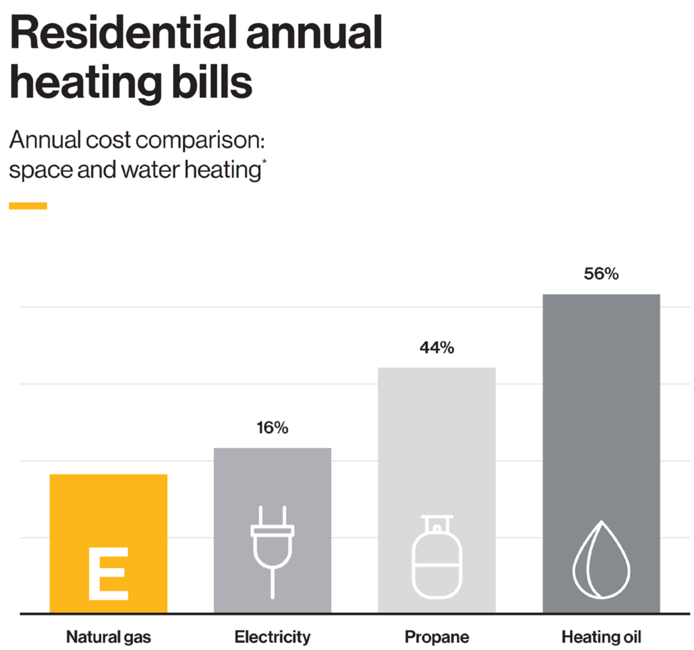
<u>Deceptive representation 1: That gas is the most cost-effective way to heat homes</u>

Various Enbridge marketing materials explicitly state that gas is the most cost-effective way to heat homes. That is false. As noted above, electric heat pumps are far less expensive for homes in Ontario. An example is excerpted below:



In addition, other materials may not *explicitly* say that gas is the most cost-effective way to heat homes, but they leave that general impression. This includes the "annual cost comparison" bar chart shown below:

[24] See, for example, the analysis in the following evidence at pages 23-24 of cost-effectiveness based on different assumptions: Evidence of the Energy Futures Group in Ontario Energy Board File # EB-2022-0200, pp. 23-24 (link).



In addition, the above bar chart explicitly states that gas heating is less expensive than electric heating, which is false. As noted above, electric heat pumps are much less expensive. Old-style electric baseboard heaters may be more expensive than gas, but that is not what Enbridge's materials state – either in the main body of the materials or the fine print. They state that annual heating is cheaper with "natural gas" versus "electricity." As another example, see the following letter sent to residents:

ENBRIDGE
Life Takes Energy

We're proud to energize the Township of Selwyn!

Dear Selwyn Resident,

Now's the time to apply for natural gas

We have some good news to share with you. Your address is identified as in scope for receiving natural gas shortly, and we want to make sure you're in the best position to connect as soon as possible. By signing up now, we'll be able to prioritize your service install as soon as the natural gas main is installed in front of your house. You may see us working on your street, including items such as survey stakes or locates.

If you're considering converting to natural gas, the earlier you apply the better as permits and locates can take time.

Refer to the Four-Step Process card when you're ready to apply, then visit **enbridgegas.com/savewithgas** to start your application. You're required to agree to the Terms and Conditions – either electronically during sign up at **enbridgegas.com/savewithgas**, or you can complete and email this to our Community Expansion Advisors at **ceapplications@enbridge.com** when the form is complete.

Unlock the value of natural gas

When compared to using electricity, propane or oil, natural gas could save you up to 54%* per year on home and water heating costs. Natural gas is also the most affordable way to run appliances like ranges, clothes dryers and barbecues.

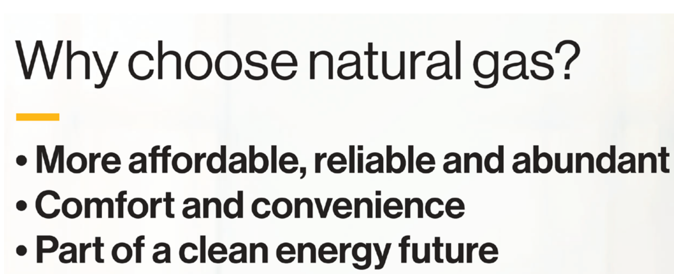
Various Enbridge marketing materials state that customers will save money by switching to gas. That may be true if a customer is switching from oil or propane. But it is highly misleading because it omits two important caveats: (a) customers could save far more by switching to an electric heat pump instead and (b) customers who already have a heat pump (which are admittedly few) would lose money by switching. An example is excerpted below:

<u>Deceptive representation 2: That methane gas is "low carbon" and "clean energy"</u>

Various Enbridge marketing materials use deceptive wording relating to heating by methane gas, including "low carbon" and "clean energy." They leave the general impression that methane gas can be accurately described with those terms and that switching to gas is environmentally conscious, which is false. Methane gas is a potent greenhouse gas that pollutes the environment and causes climate change when it is burned and when it leaks without being combusted.

Switching from propane or oil to gas may result in lower carbon emissions. But switching from electricity to gas will result in *higher* carbon emissions. And heating with heat pumps results in the lowest carbon emissions.

Two examples of deceptive representations are excerpted below:



Lower carbon emissions

Natural gas is cleaner than other fuels and can help reduce your home's carbon footprint.

Knowledge

Enbridge knows that the above representations are false, that gas is not the most cost-effective way to heat homes, and that gas is a potent greenhouse gas that contributes far more to climate change when used to heat homes in comparison to electricity.

Knowledge re cost-effectiveness of heat pumps

In 2020, Enbridge acknowledged in an Ontario Energy Board proceeding that customers would have higher annual heating costs with gas in comparison to high-efficiency electric heat pumps in gas expansion communities. This would have certainly come to the attention of upper-level Enbridge managers because it was discussed in a report of Ontario's Auditor General. The report contained the following passage:

> For example, in 2020, the OEB approved a utility proposal to construct a $10.1-million natural gas pipeline to connect new customers in North Bay. An Enbridge survey had indicated there was interest in doing so from homeowners who were using costly oil, propane or low-efficiency electric baseboards for heating. Once approved by the OEB, the project was eligible to receive a subsidy of $8.7 million to be paid by existing ratepayers. Without this subsidy the project was not economically feasible for the estimated 134 potential new natural gas customers. Even with an average subsidy of $65,000 per potential new customer, **the utility estimated that the potential customers would have higher annual heating costs than if high-efficiency electric heat pumps were used.** (emphasis added)[25]

Enbridge is also aware that heat pumps are more cost effective than gas from evidence in other proceedings it has been involved in and from a recent decision of the Ontario Energy Board, which approved incentives to switch from gas to electric heat pumps on the basis that this would be "a major benefit for customers."[26]

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[25] Office of the Auditor General of Ontario, *Value-for-Money Audit: Reducing Greenhouse Gas Emissions from Energy Use in Buildings*, November 2020, p. 18 (link).
[26] Ontario Energy Board, *Decision and Order in EB-2021-0002*, November 15, 2022, p. 28 (link).

Knowledge that methane gas is not "low carbon" or "clean energy"

According to Enbridge's own evidence in Ontario Energy Board proceedings:

- The combustion of methane gas is responsible for approximately one-third of Ontario's greenhouse gas emissions;[27] and

- Gas heating results in far more carbon emissions than electric heating, even if the electric heating is with baseboards instead of high-efficiency electric heat pumps.[28]

Harm

Enbridge's deceptive representations cause significant harm whenever they succeed in convincing a customer to connect to Enbridge's gas system instead of lowering their bills with heat pumps. Most obviously, it will result in approximately $20,000 in unnecessary costs to the customer over the lifetime of the equipment.

In addition, customers are often effectively locked into gas when they connect to the gas system. For a customer to switch over to gas, they typically must spend thousands of dollars replacing their heating equipment. Enbridge estimates the cost at $5,000 for a home heated with oil and $12,000 for a home heated with electric baseboards.[29] This effectively locks those customers into gas because it is most cost-effective to switch to an electric heat pump when your existing heating equipment requires replacement in any event. That time of "natural replacement" will not occur until their new gas equipment comes to the end of its life in roughly 15 years. Stated differently, the switch to gas wastes money on gas equipment that could have been spent switching over to a heat pump instead.

There are negative impacts on competitors too. More people converting to gas means less demand for heat pumps. This negatively impacts heat pump manufacturers, distributors, and installer. It also negatively impacts companies that generate or transport electricity.

[27] Enbridge Evidence in Ontario Energy Board File #EB-2022-0200, Exhibit 1, Tab 10, Schedule 3, Page 2 (link)
[28] Enbridge Response to Interrogatories in EB-2019-0188, Exhibit I.ED.7, Attachment 1, Page 2 (link, pdf page 180).
[29] Enbridge, *Response to Board Staff Interrogatory 4 in EB-2022-0249*, Exhibit I.STAFF.4 (link, pdf page 23). According to Enbridge, customers can convert their existing propane furnace to burn methane gas for $600. However, these customers lose the benefit of securing new heating and cooling equipment and would need to incur future equipment replacement costs when their furnace and/or their air conditioner reaches the end of its life. They will also end up with higher heating and cooling costs.

Society as a whole suffers as well. If fewer heat pumps are installed, Ontario's carbon pollution will be higher and it will be more difficult and more expensive to meet our carbon reduction targets. The carbon impacts are particularly problematic because they will persist for the lifetime of the equipment in question. If a consumer installs a gas furnace instead of a heat pump today, that choice could continue to result in higher-than-necessary carbon pollution until 2040.

Temporary orders

Environmental Defence requests that the Commissioner apply for a temporary order to stop the harm described above. Enbridge forecasts connecting 3,855 customers to its gas system in these gas expansion communities alone over 2023 to 2025.[30] If a temporary order is not made, thousands of customers could connect to the gas system while this matter is under consideration, losing approximately $20,000 each on average.

We therefore request an order that Enbridge write to all customers in the gas expansion communities and provide information on the cost-effectiveness of electric heat pumps versus gas equipment for an average customer, including all lifetime costs (equipment, heating, and cooling costs), and specific details of the rebates available for customers from the federal government, with the content to be approved by the Commissioner.

In addition, a temporary order is warranted regarding ongoing marketing. We also request an order that all future marketing materials that refer to the price of gas versus other energy options indicate the comparative cost-effectiveness of electric heat pumps versus gas equipment for an average customer, including all lifetime costs (equipment, heating, and cooling costs), and specific details of the rebates available for customers from the federal government, with the content to be approved by the Commissioner.

Disclosure re other marketing

This request primarily focuses on the deceptive marketing to customers in community expansion areas as these are the only marketing materials that we have access to. However, it is likely that deceptive representations are being made to other potential customers. This likely includes broad-based marketing and materials used with other prospective homeowners inquiring about switching to gas as well as builders and subdivision developers considering which equipment to install in new construction. These other potential customers are important. Enbridge forecasts

[30] Enbridge Gas Inc., Answer to Interrogatory from Environmental Defence in Ontario Energy Board File # EB-2022-0200, Exhibit I.2.6-ED-94, p. 5, (link) (The forecast customers over 2021 to 2023 are 2,150).

connecting over 100,000 customers between 2023 and 2025 alone (with over 13,000 switching to gas and the remaining as new construction).

We therefore request that the Commissioner require Enbridge to disclose all materials with representations relating to potential savings arising from gas, including advertising and materials that Enbridge has provided to homeowners, builders, and subdivision developers.

Although the savings from heat pumps are highest in gas expansion areas where the 23 cents/m^3 charge applies, heat pumps are still much less expensive for the average customer outside these areas.[31] These other customers are very numerous and will still lose large sums if they end up purchasing gas equipment instead of electric heat pumps.

Conclusion

Enbridge's marketing materials combine both falsehoods about the true cost of heating with gas and deceptive greenwashing. Consumers are highly susceptible to these falsehoods and deceptive messages because heat pump awareness is very low among most Ontarians. We ask that the Commissioner commence an inquiry, require further disclosure from Enbridge on its other marketing materials, institute proceedings, seek interim orders to stop the ongoing deception, and request the maximum penalties, all for the sake of protecting consumers, competition, and the climate.

Keith Brooks
Programs Director
Environmental Defence

Attachment 1: Material required by s. 9 of the *Competition Act*
Attachment 2: Marketing material in community expansion areas

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[31] Evidence of the Energy Futures Group in Ontario Energy Board File # EB-2022-0200, p. 23 (link); Dr. Heather McDiarmid, *An Analysis of the Financial and Climate Benefits of Electrifying Ontario's Gas-Heated Homes by Installing Air-Source Heat Pumps*, August 2, 2022, p. 6 (link).

Competition Bureau Canada | Bureau de la concurrence Canada

Direction générale des cartels et des pratiques commerciales trompeuses
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Cartels and Deceptive Marketing Practices Branch
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Télécopieur - Facsimile
(819) 994-2240

Téléphone - Telephone
(819) 953-3902

PROTECTED B
File: 3116431

December 12, 2023

VIA EMAIL: kent@elsonadvocacy.ca

Kent Elson, LL.B.
Elson Advocacy
1062 College Street, Lower Suite
Toronto, Ontario M6H 1A9

Dear Kent Elson:

Re: Notice of Inquiry Commencement under the *Competition Act*

Further to your application under section 9 of the Competition Act (the **"Act"**) that was received on September 7, 2023 and your letters of October 20, 2023 and November 3, 2023, I wish to inform you that the Commissioner of Competition has commenced an inquiry pursuant to paragraph 10(1)(a) and under paragraph 74.01(1)(a) of the Act, into alleged reviewable conduct by Enbridge Gas Inc. relating to representations in respect of its advertising campaign directed at gas expansion communities as well as other representations made to the public outside this campaign.

Should you have any questions, please contact Hugh Craig, Senior Counsel, Competition Bureau Legal Services, at hugh.craig@cb-bc.gc.ca.

Yours truly,

Josephine Palumbo

Josephine A.L. Palumbo
Deputy Commissioner of Competition
Cartels and Deceptive Marketing Practices Branch

c.c. Chantale Clancy, Acting Assistant Deputy Commissioner of Competition, Ontario Region, Competition Bureau
Hugh Craig, Senior Counsel, Competition Bureau Legal Services
Kendra Wilson, Counsel, Competition Bureau Legal Services
Lina Nikolova, Senior Competition Law Officer, Competition Bureau

Canada

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit I, Tab 1, Schedule 1

Question(s):

(a) Would Enbridge agree to the following condition of approval? If not, please explain why not and provide alternative wording for a commitment that Enbridge would make.

> "The Applicant shall provide potential customers with a comparison of the average annual energy costs and lifetime all-in costs of converting to gas versus converting to a cold climate air source heat pump."

(b) Please provide a copy of:
  - (i) All promotional or informational materials sent to customers in community expansion areas that have connected to the gas system in the past three years, including materials sent by mail, email, or social media;
  - (ii) A copy of all newspaper and online advertisements relating to switching to gas in the past three years; and
  - (iii) A copy of all Enbridge website pages relating to switching to gas.

(c) For the items in (b) that are undated, please indicate the date range during which they were sent to customers or published.

(d) Please provide a copy of all Enbridge communication plans or communication strategy documents relating to community expansions or switching to gas more generally.

Response

(a) No.

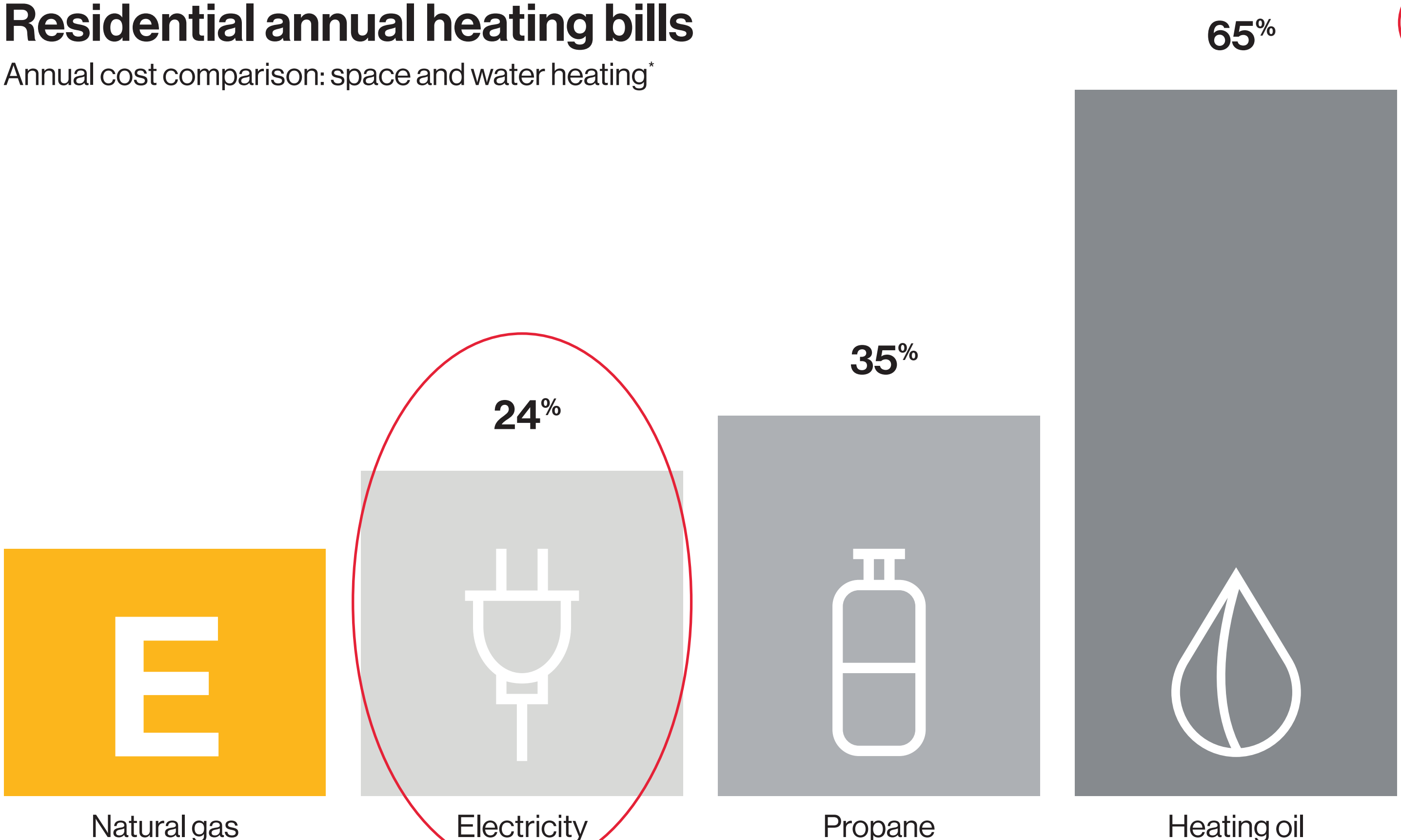
Cost and benefits

How much can you save each year?

Lower costs, lower emissions, more convenience and peace of mind.

Residential annual heating bills

Annual cost comparison: space and water heating*



* Natural gas prices are based on Rate 1 rates in effect as of **April 1, 2023** and include the $0.23 per m^3 expansion surcharge. Oil price is based on the latest available retail price. Electricity rates based on Hydro One Distribution rates (Mid-density R1) as of **Jan. 1, 2023** and Regulated Price Plan (RPP) customers that are on Time-Of-Use (TOU) pricing. They include the new Ontario Electricity Rebate (OER). The propane price comparison is based on the lowest price obtained in an area survey conducted quarterly. Since individual fuel prices vary, savings assumptions may or may not be as accurate in your situation. Please use the savings calculator found on this page for a more accurate savings estimate. Costs have been calculated for the equivalent energy consumed and include all service, delivery and energy charges. Carbon price is included for all energy types as reported. HST is not included.

Bring home all the benefits

More affordable
Compared to other fuels and electricity, natural gas is the most cost-effective way to heat your home and water.

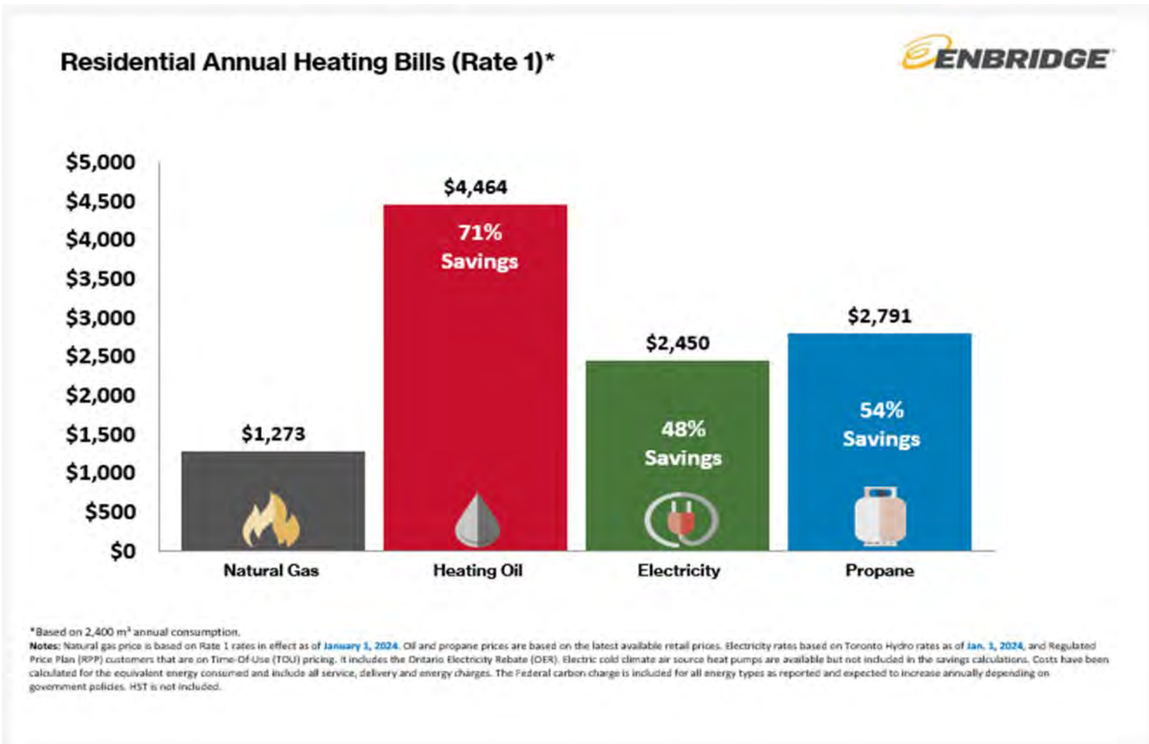
Comfort and convenience
Never worry about running out of fuel or waiting for deliveries again.

Versatile and efficient
From fireplaces to clothes dryers, natural gas can make your home more comfortable and enjoyable.

Lower carbon emissions
Natural gas can help reduce your home's carbon footprint.

briefings (e.g., OEB, government, HVAC industry). An example of the energy comparison information chart is presented below. The example corresponds to the "Residential Annual Heating Bill (Rate 1)" produced for the January 2024 QRAM update.

Figure 1: Residential Annual Heating Bill (Rate 1) – January 2024



4. The energy comparison information illustrates an estimated energy equivalent annual heating bill[2] for conversions from three standard existing energy sources (i.e., heating oil, propane, and electric resistance heating) to natural gas, for a typical residential consumer in Rate 1, Rate M1 and Rate 01 (North East and North West). Greater details regarding the specific assumptions underpinning the energy comparisons are provided later in Section 2 of this evidence.

[2] Annual heating bill implies heat load (space heating) and base load (water heating).

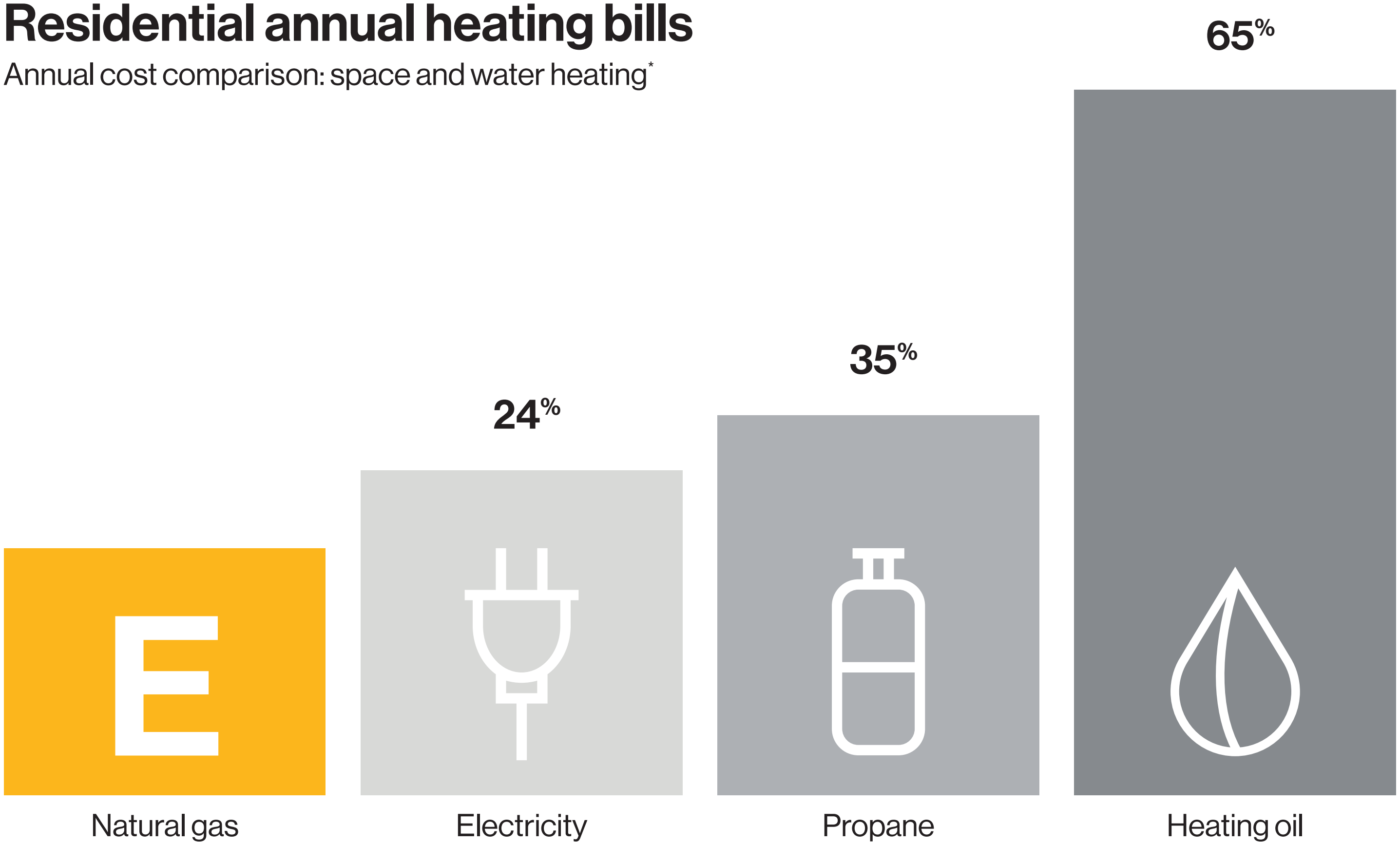
Cost and benefits

How much can you save each year?

Lower costs, lower emissions, more convenience and peace of mind.

Residential annual heating bills

Annual cost comparison: space and water heating*



* Natural gas prices are based on Rate M1 rates in effect as of ~~**April 1, 2023**~~ and include the $0.23 per m³ expansion surcharge. ~~Oil price is based on the latest available retail price. Electricity rates based on Hydro One Distribution rates (Mid-density R1) as of **Jan. 1, 2023** and Regulated Price Plan (RPP) customers that are on Time-Of-Use (TOU) pricing. They include the new Ontario Electricity Rebate (OER). The propane price comparison is based on the lowest price obtained in an area survey conducted quarterly. Since individual fuel prices vary, savings assumptions may or may not be as accurate in your situation. Please use the savings calculator found on this page for a more accurate savings estimate. Costs have been calculated for the equivalent energy consumed and include all service, delivery and energy charges. Carbon price is included for all energy types as reported. HST is not included.~~

Natural gas prices are based on M1 rates in effect as of Jan. 1, 2024 and include the $0.23 per m3 expansion surcharge. Electricity rates based on Hydro One Distribution rates (Mid-density R1) as of Jan. 1, 2023 and Regulated Price Plan (RPP) customers that are on Time-Of-Use (TOU) pricing. They include the new Ontario Electricity Rebate (OER). Electric cold climate air source heat pumps are available but not included in the savings calculations. The propane price comparison is based on the lowest price obtained in an area survey conducted quarterly. Oil price is based on the latest available retail price. Since individual fuel prices vary, savings assumptions may or may not be as accurate in your situation. Costs have been calculated for the equivalent energy consumed and include all service, delivery and energy charges. The Federal carbon charge is included for all energy types based on the Jan. 1, 2024 rate. The Federal carbon charge is projected to increase annually from 2024 to 2030.

Bring home all the benefits

Cost effective
~~**More affordable**~~

Compared to other fuels and electricity, natural gas is ~~the most cost-effective way~~ a cost-effective way to heat your home and water.

Comfort and convenience

Never worry about running out of fuel or waiting for deliveries again.

Versatile and efficient

From fireplaces to clothes dryers, natural gas can make your home more comfortable and enjoyable.

Lower carbon emissions

Natural gas can help reduce your home's carbon footprint.

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

January 24, 2024

Your Worship and Members of Council,

I am writing to inform you of our concerns with the Ontario Energy Board's (OEB) decision on Phase 1 of the Enbridge Gas 2024 rebasing application, issued on December 21, 2023. The disappointing decision puts future access to natural gas in doubt and sets a deliberate course to eliminate natural gas from Ontario's energy mix. This decision is about the millions of Ontarians who rely on natural gas to keep their homes warm, and the many businesses throughout Ontario who depend on natural gas for day-to-day operation.

Our 2024 rate rebasing application was designed to provide our customers with safe and reliable natural gas at a reasonable cost, in addition to measured steps to help Ontario advance a practical transition to a sustainable energy future. Natural gas plays a critical role in Ontario's energy evolution mix while supporting the reliability of Ontario's electricity system. Natural gas meets 30 percent of Ontario's energy needs, which can not be easily or quickly replaced.

We are taking action to secure the future of natural gas in your communities. We are filing a motion in late January to review evidence with the OEB and seeking a judicial review of this decision.

Without natural gas, communities across Ontario will feel the impacts of this decision in their everyday lives – the stakes are high.

- **Energy Affordability**: Those looking to connect to natural gas will be required to pay an upfront fee, which creates a significant financial barrier to all forms of residential and commercial development. This resulting fee adds thousands of dollars to individual consumers' cost to obtain or expand gas service.

- **Economic Growth**: This decision will put economic developments in your community at risk. The decision limits the ability of future expansion projects to support regional investment to meet the ever-growing energy needs in your community and communities across Ontario. That includes greenhouses, grain dryers, industrial parks, and any new businesses or housing developments seeking access to natural gas.

- **Energy Access**: Preserving customer choice is critical. Constraining access to natural gas through a reduction in capital will significantly limit the future development of essential energy infrastructure vital to moving manufacturing, agriculture, and the consumer goods industry in Ontario.

- **Energy Security**: On an annual basis, natural gas delivers twice the energy to Ontario than electricity, and five times the maximum peak capacity of Ontario's electricity grid at a quarter of the cost. Even in the worst weather conditions, our reliable natural gas system delivers.

As local leaders across the province, your voice matters, and we encourage you to take action.

Reach out to your MPP to share your support for the government's quick action and write the OEB about the consequences of reduced access to the natural gas grid to support economic development, housing growth, energy reliability. Use your voice to acknowledge the need for natural gas and infrastructure in Ontario today and into the future while we take a measured step towards energy transition.

We ask that you reach out to your municipal advisor or find us at municipalaffairs@enbridge.com to get started.

Sincerely,

Michele Harradence
President
Enbridge Gas Inc.

Enbridge Sustain Business Plan

Financial Deep Dive

A simple, affordable way to adopt sustainable energy solutions

ENBRIDGE Sustain

Sept 1, 2023

ENBRIDGE Sustain

Financial Implications of Roll-out Scenarios

The full range of financial scenarios modeled yielded DCFROE of [redacted]% to [redacted]% and 10-year capital expenditures of [redacted] to [redacted] respectively

	Growth Spectrum	**Lower Growth** **Lower returns** and budgetary needs	**Higher Growth** **Higher** capital and opex needs
Key Financials	5 Year Capex (B,$) – cumulative 10 Year Capex (B,$) – cumulative	[redacted]	[redacted]
	5 Year Revenue (M,$) – cumulative 10 Year Revenue (B,$) – cumulative	[redacted]	[redacted]
	EBITDA in Year 10 (M,$) CAGR, Year 1 – Year 10	[redacted]	[redacted]
	DCF in Year 10	[redacted]	[redacted]
	DCFROE	[redacted]	[redacted]
	DCFROE[1] *(including retained gas margin)*	[redacted]	[redacted]
Assumptions	2024 Fixed O&M (M,$) 2028 Fixed O&M (M,$)	[redacted]	[redacted]
	Headcount / Labor	2024: ~95 (~30 variable) [redacted]	2024: ~130 (~50 variable) [redacted]
	Share of Hybrid Heating sales in yr. 5 Share of overall HVAC sales: in yr. 5	[redacted]	[redacted]

Note(s): [1]Assuming [redacted] of new customers who sign up for hybrid heating would have moved to [redacted] electric heating and cooling otherwise.
Variable = flexes up only with positive growth in the organization.

Overall Financial Summary (1 of 2)

ENBRIDGE Sustain

A lower growth scenario was modeled, yielding a [redacted]% DCFROE and returning positive EBITDA in four years

Lower Growth Scenario Financial Summary

in CAD$MM	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]						[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

DCFROE	[redacted]

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Cumulative
Gas Distribution Margin retained due to Hybrid Heating Program (Not included in financials above) **Based on % of customers assumed would move to 100% electrical heating & cooling**	10%	-	0.6	1.4	2.5	3.7	-	1.5	3.0	4.7	6.6	**8.2**
	20%	-	1.1	2.8	5.0	7.3	-	2.9	6.1	9.5	13.2	**16.4**
	30%	-	1.7	4.2	7.5	11.0	-	4.4	9.1	14.2	19.7	**24.7**
	40%	-	2.2	5.6	10.0	14.7	-	5.9	12.2	19.0	26.3	**32.9**
	50%	-	2.8	7.0	12.5	18.3	-	7.3	15.2	23.7	32.9	**41.1**
	60%	-	3.3	8.4	15.0	22.0	-	8.8	18.3	28.5	39.5	**49.3**
	70%	-	3.9	9.8	17.4	25.7	-	10.2	21.3	33.2	46.0	**57.6**
	80%	-	4.5	11.2	19.9	29.3	-	11.7	24.3	38.0	52.6	**65.8**
	90%	-	5.0	12.6	22.4	33.0	-	13.2	27.4	42.7	59.2	**74.0**
	100%	-	5.6	14.0	24.9	36.6	-	14.6	30.4	47.4	65.8	**82.2**

Overall Financial Summary (2 of 2)

ENBRIDGE Sustain

A higher growth scenario was modeled, yielding a [redacted]% DCFROE and returning positive EBITDA in three years

Higher Growth Scenario Financial Summary

in CAD$MM	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
[redacted]	[redacted]	[redacted]		[redacted]							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

DCFROE	[redacted]

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Cumulative
Gas Distribution Margin retained due to Hybrid Heating Program (Not included in financials above) **Based on % of customers assumed would move to 100% electrical heating & cooling**	10%	-	0.6	1.4	2.5	3.7	-	1.5	3.0	4.7	6.6	**23.9**
	20%	-	1.1	2.8	5.0	7.3	-	2.9	6.1	9.5	13.2	**47.9**
	30%	-	1.7	4.2	7.5	11.0	-	4.4	9.1	14.2	19.7	**71.8**
	40%	-	2.2	5.6	10.0	14.7	-	5.9	12.2	19.0	26.3	**95.8**
	50%	-	2.8	7.0	12.5	18.3	-	7.3	15.2	23.7	32.9	**119.7**
	60%	-	3.3	8.4	15.0	22.0	-	8.8	18.3	28.5	39.5	**143.7**
	70%	-	3.9	9.8	17.4	25.7	-	10.2	21.3	33.2	46.0	**167.6**
	80%	-	4.5	11.2	19.9	29.3	-	11.7	24.3	38.0	52.6	**191.6**
	90%	-	5.0	12.6	22.4	33.0	-	13.2	27.4	42.7	59.2	**215.5**
	100%	-	5.6	14.0	24.9	36.6	-	14.6	30.4	47.4	65.8	**239.4**

By EMAIL and RESS

Jay Shepherd
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August 26, 2024
Our File: HV 2024-0011

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attn: Nancy Marconi, Registrar

Dear Ms. Marconi:

Re: EB-2024-0111 – Enbridge Rebasing Phase 2 – Confidentiality Claim

We are counsel for the Heating, Refrigeration and Air Conditioning Institute of Canada (HRAI). This letter is being sent in response to the letter of the Applicant's counsel dated August 23, 2024.

HRAI divides the issue of confidentiality as claimed by the Applicant into two distinct components.

At one level, there is the general question of whether the items redacted in the undertaking responses are appropriately treated as confidential under the OEB's Practice Direction. To make submissions on this question, counsel and our instructing representative Mr. Luymes will have to look at the redactions themselves, and we have (intentionally) not done so as yet. The general issue of confidentiality appears to be less urgent, because the proceeding can continue on its current schedule in parallel with this question being resolved. We assume that the Commissioners will establish a process for submissions on that.

The more pressing issue is the additional request that HRAI's potential witnesses be uniquely prohibited from looking at the redacted material, even if they sign Declarations and Undertakings (as they have done). This is a significant problem, because they will not even be able to start to prepare evidence until they have the numerical data that is redacted. Their evidence is due this Friday.

It is for this reason that this letter is being sent before an OEB Procedural Order, and before counsel has reviewed the redactions. When counsel meets with the witnesses in the next couple of days, it is important that we not be in a position to inadvertently disclose, directly or indirectly, the redacted information.

There would appear to be two categories of information that the witnesses could learn from the redacted information.

First, they could learn the size of the HVAC market Enbridge Sustain believes it can acquire, through seeing the revenue numbers and knowing, from the public filing, the Enbridge Sustain pricing. These witnesses know their own revenues, and those of other companies in the sector, and so can ascertain the Enbridge Sustain forecast market share.

However, the public information already provides sufficient information that one could make an informed guess as to the market share expected. Of particular importance is the estimates of distribution margin protected through sales of hybrid heating (which cause customers to commit to keeping their gas connection, and avoiding full electrification). These estimates range from a low of $57.6 million (Exhibit I-1-18-HRAI-5, Attachment 3, at p 23) to a high of $167.6 million (p. 24), in each case at their forecast that 70% of hybrid heating customers would otherwise have gone fully electric. This implies distribution margins from those residential customers that buy hybrid heating from Enbridge Sustain of $82.3 million to $239.4 million, which translates into between 165,000 and 480,000 hybrid heating systems installed in that time frame until 2033 (based on the EB-2022-0200 DRO, Schedule 19, which forecasts annual distribution margin per residential customer of about $500 each).

While estimates such as these are obviously subject to a lot of variables, and so are not accurate, within a reasonable margin for error they tell the story quite well. It is not clear that witnesses would learn much more about Enbridge Sustain forecast market share from the redacted information.

Second, witnesses could learn the forecast pricing and cost parameters of Enbridge Sustain.

In part, this is also known, both in the industry and from the public version of the documents filed. A typical hybrid heating system will be delivered into the market at a price of about $200 a month (Attachment 3, p. 45), which is similar to the major competitors. The market is sufficiently competitive that companies participating in it are price-takers.

The question, therefore, is how can Enbridge Sustain make a profit, charging competitive or even slightly better prices than other companies? We know Enbridge exited this business earlier because it failed to make it profitable. What has changed? That is the key question facing this OEB panel, since one of the two sources of that profitability is a ratepayer subsidy. Given that the other source is a shareholder subsidy, and that the Business Plan makes clear that there is no shareholder appetite to fund this initiative, a ratepayer subsidy seems likely.

Table 2

Annual Average Incremental Operational Costs

Line No.	Item	O&M Cost
1	Distribution Operations	$17.77
2	Customer Care	$50.66
3	Employee Benefits	$6.45
4	Average Total O&M Cost per Residential Customer	$74.89

e) Yes.

ENBRIDGE GAS INC.

Answer to Environmental Defence Motion Question

Reference:

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

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

Question:

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

Response[1]:

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

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

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

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

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

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

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

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

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

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

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

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

Table 2

Estimate of Incremental Revenue Requirement of Attaching Feasible Rate 1 Customers

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

Notes:

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

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

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

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

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

Notes:

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

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

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

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

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

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

Notes:

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

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

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

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

Updated Response: /u

By letter dated December 4, 2024, ED requested Enbridge Gas to update its response to motion question #3 to indicate “the cost of an additional customer incremental to the costs already covered by base rates.” The Company confirms that it believes its original response remains appropriate. The Company agrees that base rates can support a certain level of capital spending, in total. However, base rates and the annual escalation of those rates under a price cap rate setting mechanism during an incentive regulation (“IR”) term are not allocated to a specific type of capital expenditure recovered within rates. Generally, revenue growth through price cap escalation alone is insufficient to fully fund the cost associated with capital required to add customers and maintain safe and reliable service during the IR term. Growth and efficiencies are required to make up the difference and to earn allowed ROE under incentive regulation. What is clear is that there are incremental capital and operating costs associated with adding customers, that would not otherwise be incurred in the absence of doing so.

As part of the regulatory compact, the Company is obligated to serve new customers in return for the revenues generated from them. The obligation to serve is not compatible with the decoupling mechanisms proposed by ED, which are contrary to the OEB’s established rate setting mechanisms. The incremental revenues from customer growth are required to fund the necessary capital investments which enable the Company to add customers.

Further, when viewed in isolation, the cost of adding a customer typically outweighs the incremental revenues received from that customer in the first number of years. This is because the carrying costs of the associated capital costs are highest in the early years, but slowly decrease over time as the cost of assets are recovered through depreciation, whereas rates/revenues reflect an average carrying cost of assets (due to the varied mix of assets at all ages reflected in rate base). As a result, in the near term, where rates are set through a price cap mechanism, not cost of service, the addition of customers actually creates a drag on earnings, not a windfall.

Table 5 illustrates the forecast impact of customer additions over the IRM term. The forecast costs are shown at line 15 and reflect the cumulative revenue requirement of customer connection capital plus incremental operating costs per customer addition. Customer addition revenues, which are shown on line 18, reflect the revenue requirement associated with 2024 customer connection capital which is embedded in base rates and subject to annual PCI escalation, plus the cumulative gross margin associated with customer additions. Finally, line 19 provides the variance between customer addition costs and revenues, which shows the costs of customer connections outweigh the associated revenues. Of course, this issue would be amplified if the Company were not permitted to retain incremental revenues from new customer additions during the IRM term.

Table 5
Revenue Shortfall in IRM Term for Illustration

Line No.	Particulars	2024	2025	2026	2027	2028
		(a)	(b)	(c)	(d)	(e)
1	PCI (%)		3.3%	1.7%	1.7%	1.7%
2	Customer Adds ($) (1)		40,533	38,879	37,000	35,200
3	Revenue/ Customer($) (2)	600	620	631	641	652
4	O&M/ customer ($) (3)	94	97	99	100	102
5	Property Tax /Customer ($) (3)	14	14	15	15	15
6	Capital Expenditures ($Millions) (4)	224	286	256	230	208
	Revenue Requirement ($Millions)					
7	RR- 2024 Customer Adds	(5)	21	21	21	20
8	RR- 2025 Customer Adds	-	(5)	27	26	26
9	RR- 2026 Customer Adds	-	-	(2)	24	23
10	RR- 2027 Customer Adds	-	-	-	(1)	21
11	RR- 2028 Customer Adds	-	-	-	-	3
12	Total RR Capital Related (sum of lines 7 to 11)	(5)	17	45	70	94
13	O&M (line 2 x line 4)		4	8	11	15
14	Property Tax (line 2 x line 5)		1	1	2	2
15	Total Cost (sum of lines 12 to 14)		21	54	83	111
16	Base Revenue Escalated @ PCI	(5)	(5)	(5)	(5)	(6)
17	Customer Growth-Revenue (line 2 x line 3)		25	50	73	96
18	Total Revenue- Customer Adds		20	44	68	91
19	Revenue Shortfall (line 15 - line 18)		1	10	15	20

Notes:

(1) Customer additions based on AMP filed Nov 8, 2024.
(2) $600 per customer is the average for all general service customers, provided in Table 1, escalated for PCI in line 1.
(3) O&M and property tax based on Table 2, line 3, column (a).
(4) 2024 Customer Growth based on Phase 1 Rate order, and 2025-2028 based on AMP filed November 8, 2024.

The Company also notes that rate base growth and the associated carrying costs (i.e. cost of capital and depreciation expense and taxes), which has resulted from the level of capital expenditures required to maintain the safe operation of the system (i.e. through replacement of long lived assets, being replaced in current dollars) and meet growth requirements, has exceeded the revenue growth that is attributable to solely PCI escalation of base rates. Revenue growth due solely to PCI escalation is not sufficient to support the costs associated with capital requirements.

Revenues associated with PCI, growth, and cost efficiencies have been leveraged under the Price Cap rate setting mechanism to accommodate capital requirements. As rates are not tied to costs under a price cap mechanism, the ability to offset cost pressures in one area through efficiencies or revenue growth (i.e. scale economies) is a key attribute to the mechanism. The revenues achieved through the Price Cap mechanism should be treated as a whole (not segregated). This allows a utility to allocate funds across a variety of cost categories including O&M, capital and cost of capital. Isolating revenues by specific cost categories, such as growth capital contradicts the principles of Performance Based Regulation (PBR) and restricts the utility's operational flexibility.

The expectation that incremental revenues from the growth capital enables the funding of additional capital is reflected by the inclusion of the growth (g) factor in the ICM formula. The purpose of the g-factor is to account for the incremental capital funding that is notionally expected to be funded through existing rates resulting from revenues achieved from growth. By incorporating the g-factor, the ICM formula ensures that the incremental revenues generated from customer growth are recognized before incremental capital funding is awarded.

Finally, the imposition of either of the proposed decoupling mechanisms would impede the Company's ability to earn its allowed rate of return and a fair return, in any circumstance where more revenues are being returned to customers as compared to the cost offsets recognized. This impact is additive over an incentive regulation term.

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ENBRIDGE GAS INC.

Answer to Environmental Defence Motion Question

Question(s):

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

Response:

Table 1
Forecast Customer Additions

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

Note:

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

Table 2
Forecast Customer Exits

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

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

annual capital expenditures by Asset Class, as shown in the Capital Update provided at Exhibit 2, Tab 5, Schedule 4. Categories of spend not included in the Asset Management Plan (AMP) include Community Expansion and Other which includes Renewable Natural Gas (RNG) and Compressed Natural Gas (CNG). /u

Table 1
Utility Capital Expenditures by Asset Class

Line No.	Particulars ($ millions)	Category	2024 Test Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	
			(a)	(b)	(c)	(d)	(e)	
1	Compression Stations	Storage	46.3	64.3	50.3	127.6	19.2	/u
2	Customer Connections	Growth	304.1	248.1	256.9	254.0	250.1	/u
3	Distribution Pipe	Dist Ops	357.1	414.4	282.7	250.2	316.4	/u
4	Distribution Stations	Dist Ops	83.5	113.1	105.5	79.0	116.3	/u
5	Fleet & Equipment	General	31.5	35.4	40.1	45.7	52.3	/u
6	Growth - Distribution System Reinforcement	Growth	85.2	200.0	43.4	46.0	10.3	/u
7	Real Estate & Workplace Services	General	63.0	61.3	92.0	32.0	56.4	/u
8	Technology Information Services	General	102.4	78.0	71.0	44.9	54.1	/u
9	Transmission Pipe and Underground Storage	Storage	69.2	144.8	201.5	268.4	169.9	/u
10	Utilization	Dist Ops	152.3	160.1	172.6	152.0	168.4	/u
11	EA Fixed Overhead	Other	39.8	40.8	41.9	43.0	23.2	/u
12	Community Expansion	Growth	11.2	19.6	20.5	21.5	7.3	/u
13	Other	Other	124.6	43.9	28.3	28.0	35.7	/u
14	Total		1,470.3	1,623.8	1,406.7	1,392.3	1,279.5	/u

Notes:
(1) Expenditures are shown by Asset Class inclusive of IDC and Overheads and net of contributions
(2) Expenditures are shown on an annual basis
(3) Panhandle Regional Expansion Project capex reductions of $194.9M in 2024 and $6.7M in 2025

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 27

To update the table to include meters and any other capital connection costs not currently included.

Response:

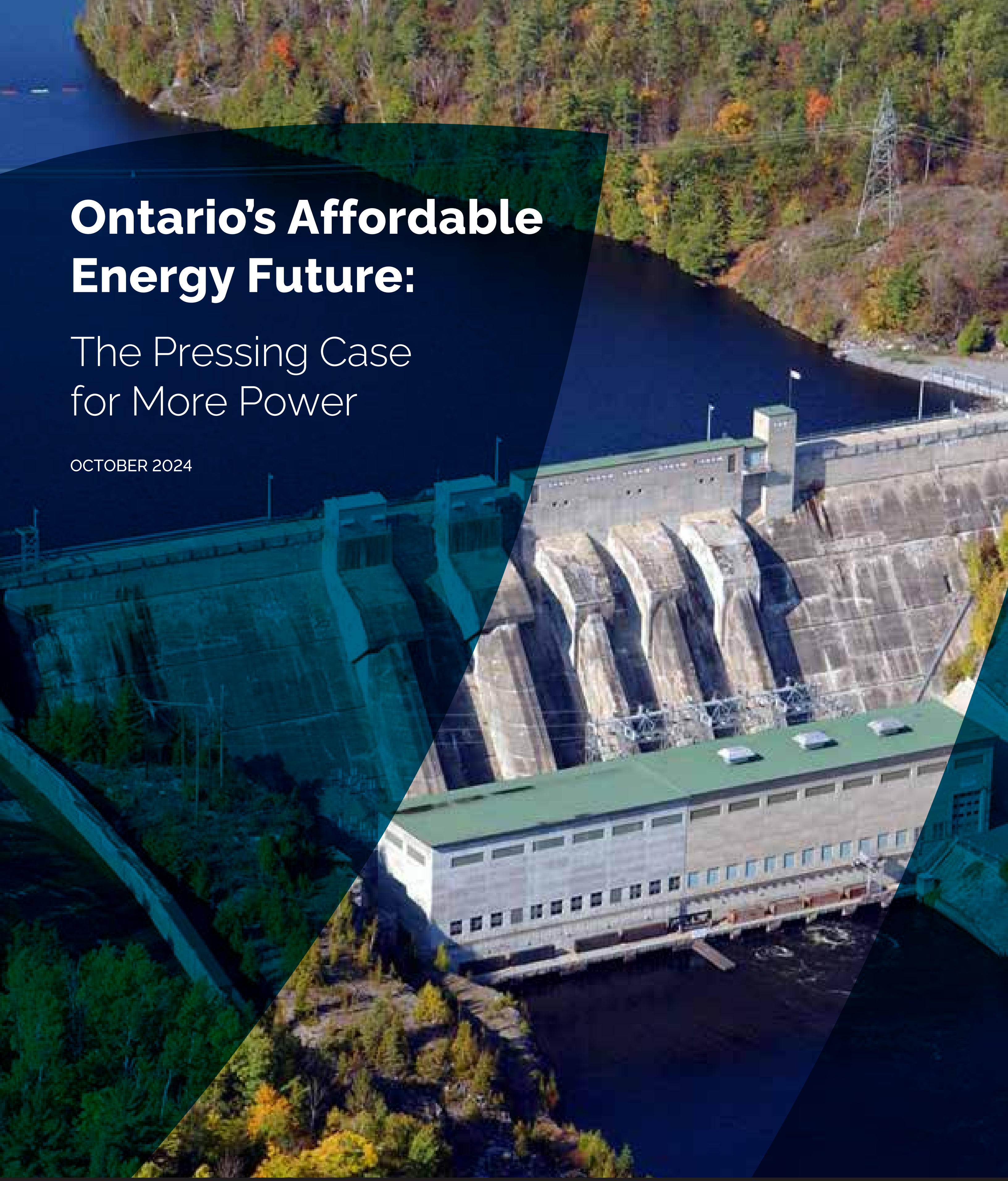
Please see Table 1, which has been updated to include meters and other costs associated with new customer connections. Table 1 also includes corrections to the 25-year and 30-year scenarios noted in the updated response to Exhibit J10.11.

Table 1
Customer Connections Capital Expenditure Plus Other related Costs Supported by Different Revenue Horizons

Revenue Horizons	2024	2025	2026	2027	2028	Total	Reduction vs 40-Year Revenue Horizon	CIAC per Customer
(Years)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	
40	359	304	316	315	286	1,579		
30	284	283	298	302	289	1,456	123	637
25	265	264	278	282	271	1,361	218	1,131
15	201	201	212	215	195	1,024	554	2,875
10	144	144	153	156	132	729	850	4,409

Notes:
1. 40-year revenue horizon reflects the Company's Capital Update in Exhibit 2, Tab 5, Schedule 4 filed on June 16, 2023
2. Table 1 includes the following costs associated with new customer connections:

a) Direct capital cost
b) Capitalized overheads
c) Meter costs
d) Fixed EA overheads



Ontario's Affordable Energy Future:

The Pressing Case for More Power

OCTOBER 2024

MINISTRY OF ENERGY AND ELECTRIFICATION

Ontario

Table of Contents

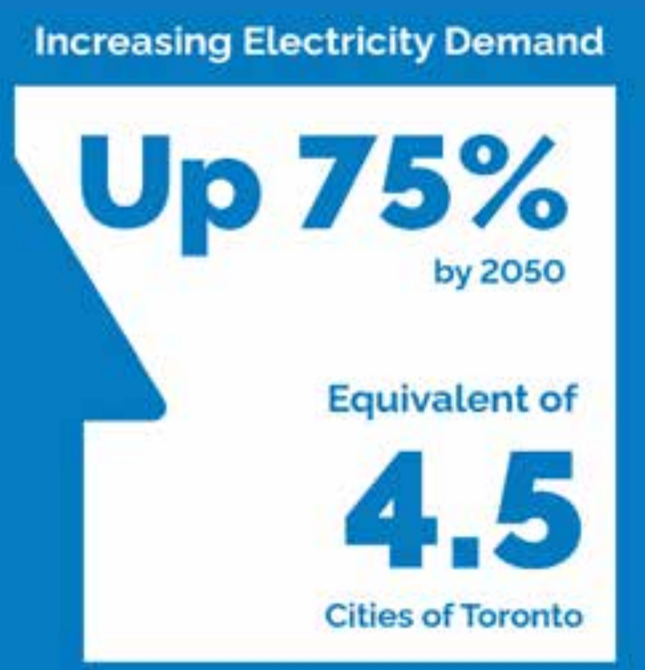
Minister's message

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

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

We got to work.

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



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Stephen Lecce

Ontario's Minister of Energy and Electrification

How We Got Here: Fixing the Hydro Mess

Introduction

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

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

Step One: Getting Electricity Bills Under Control

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

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

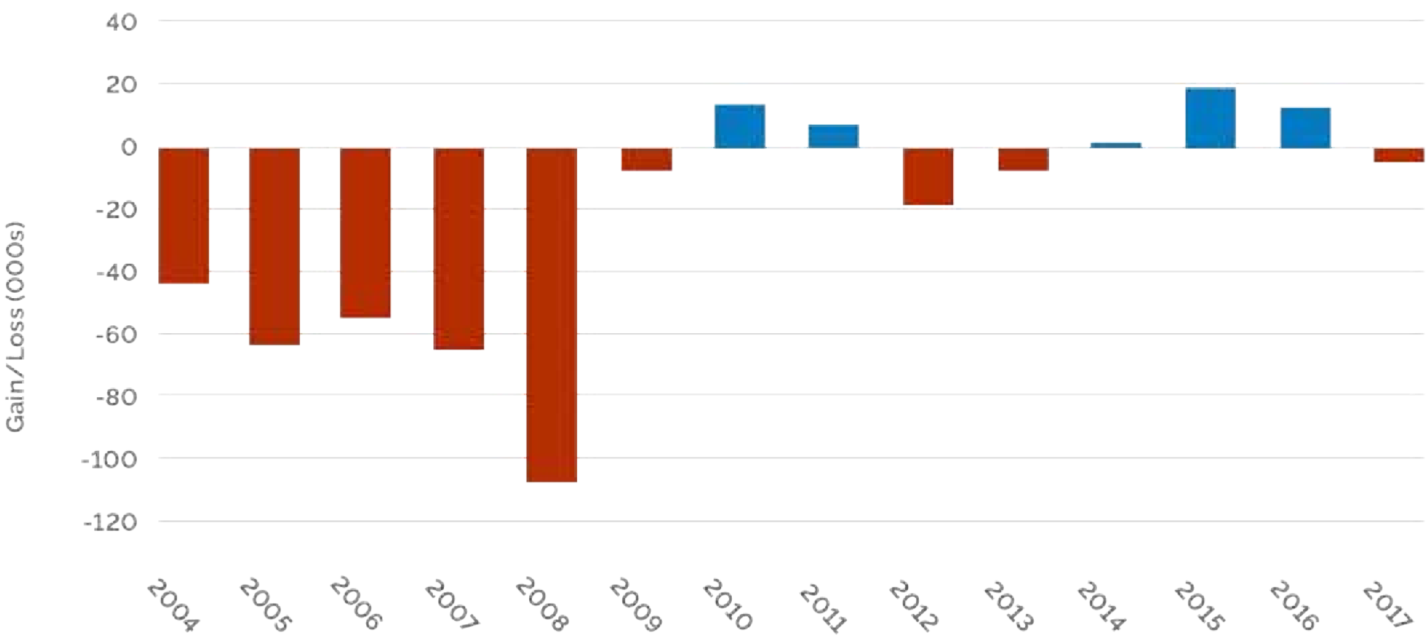
Rural and northern Ontarians were uniquely disadvantaged with fewer options to meet their energy needs.

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

Manufacturing Jobs Lost to High Electricity Prices

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

Figure 1: Manufacturing Job Losses Per Year



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

Comprehensive Electricity Plan (CEP)

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

Ontario Electricity Rebate (OER)

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

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

Sample Bill with OER and CEP

Account Number: 000 000 000
November 2023

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

Sample Bill without OER and CEP

Account Number: 000 000 000
November 2023

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

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

Step Two: Powering Ontario's Growth

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

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

Nuclear

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

Nuclear Energy Creates Local Jobs

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

Refurbishments

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

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

Nuclear: On-Time and On-Budget

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

New Build at Bruce Power

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

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

Small Modular Reactor (SMR) Program

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

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

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

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

Nuclear Energy Saves Lives: Medical Isotopes

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

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

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

Hydroelectricity

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

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

Competitive Procurements

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

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

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

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

Energy Efficiency

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

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

Energy Efficiency Programs Put Money in Families' Pockets

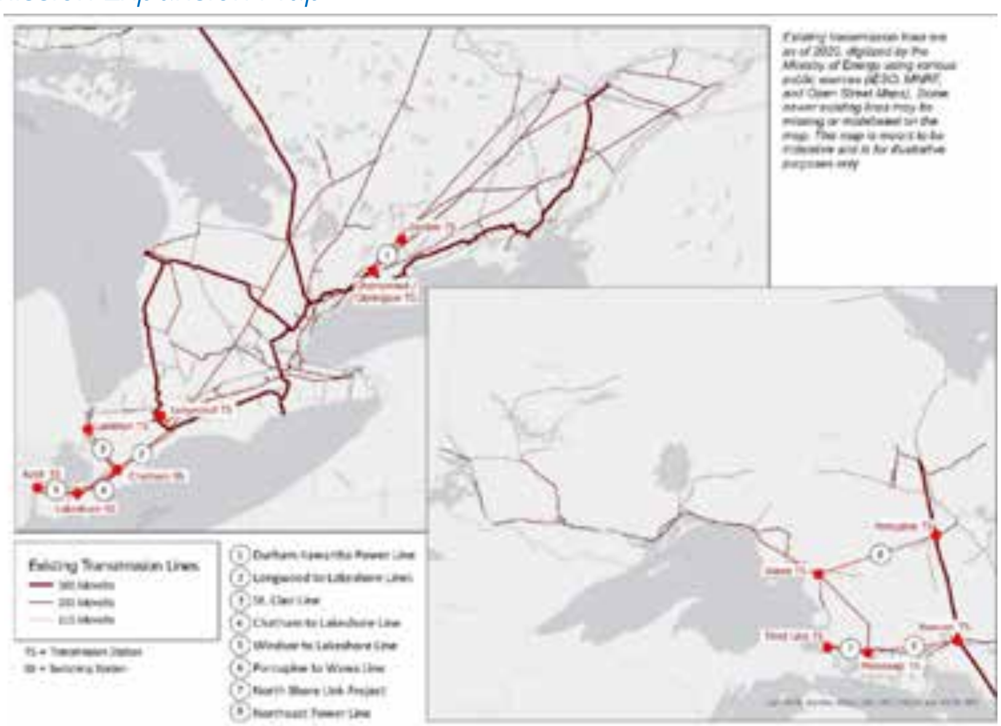
In June 2023 the government launched the new Peak Perks program to help families save money by reducing their electricity usage during peak periods. In just over a year, the program has already enrolled over 150,000 families and is providing them an upfront incentive of $75 and $20 for each additional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

Transmission Expansion

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

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

Figure 3: Transmission Expansion Map

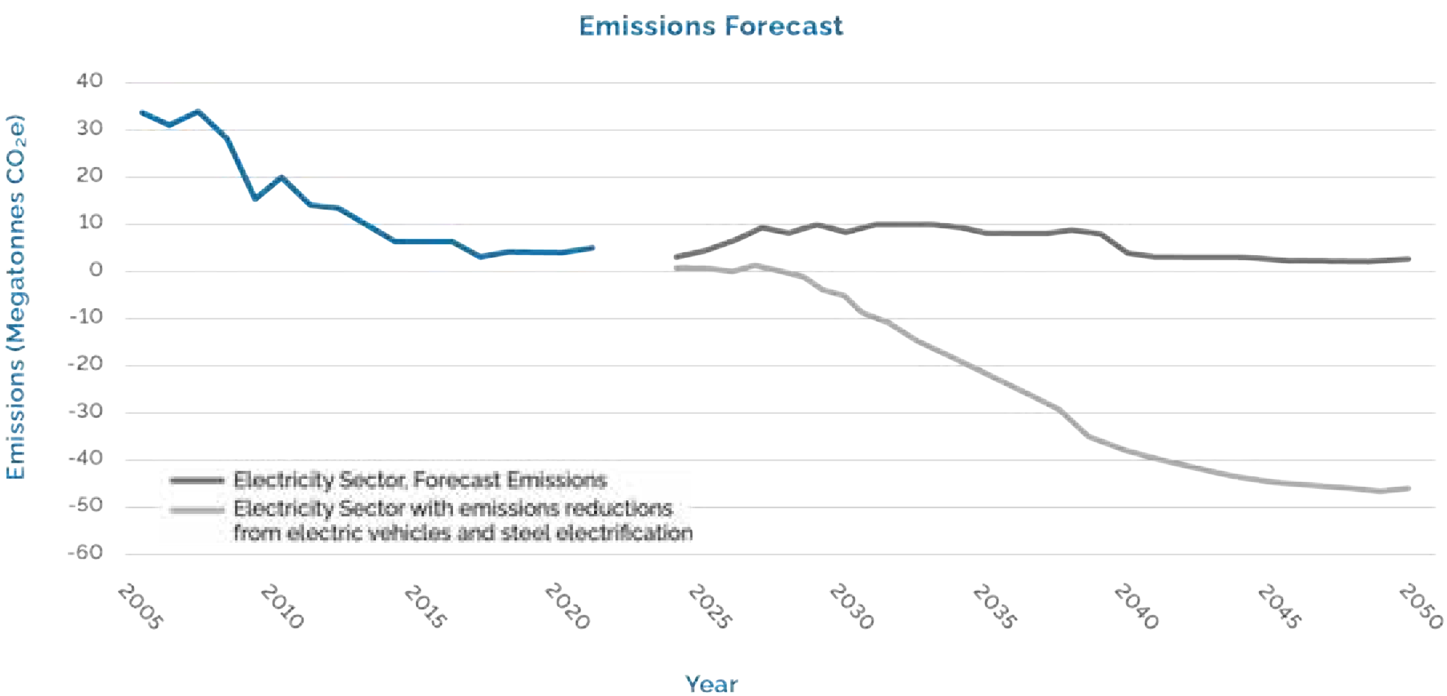


Step Three: Ontario's Clean Grid Reduces Provincewide Emissions

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

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

Figure 4: Province-wide Emissions Forecast



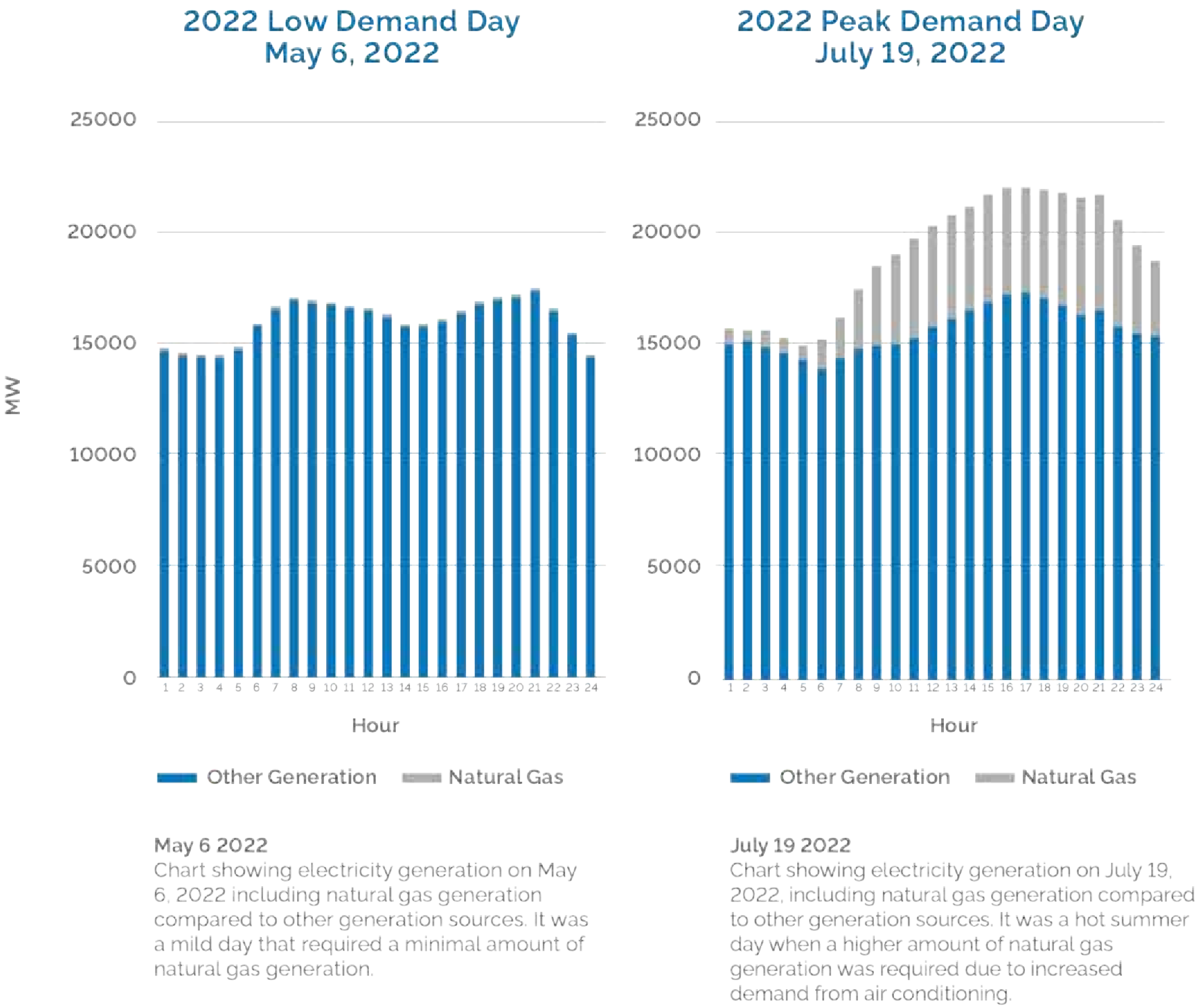
Source: Historical data sourced from Environment and Climate Change Canada's 2024 Greenhouse Gas National Inventory Report

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

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

Why Ontario Needs Natural Gas in the Short-Term

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



Source: IESO

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

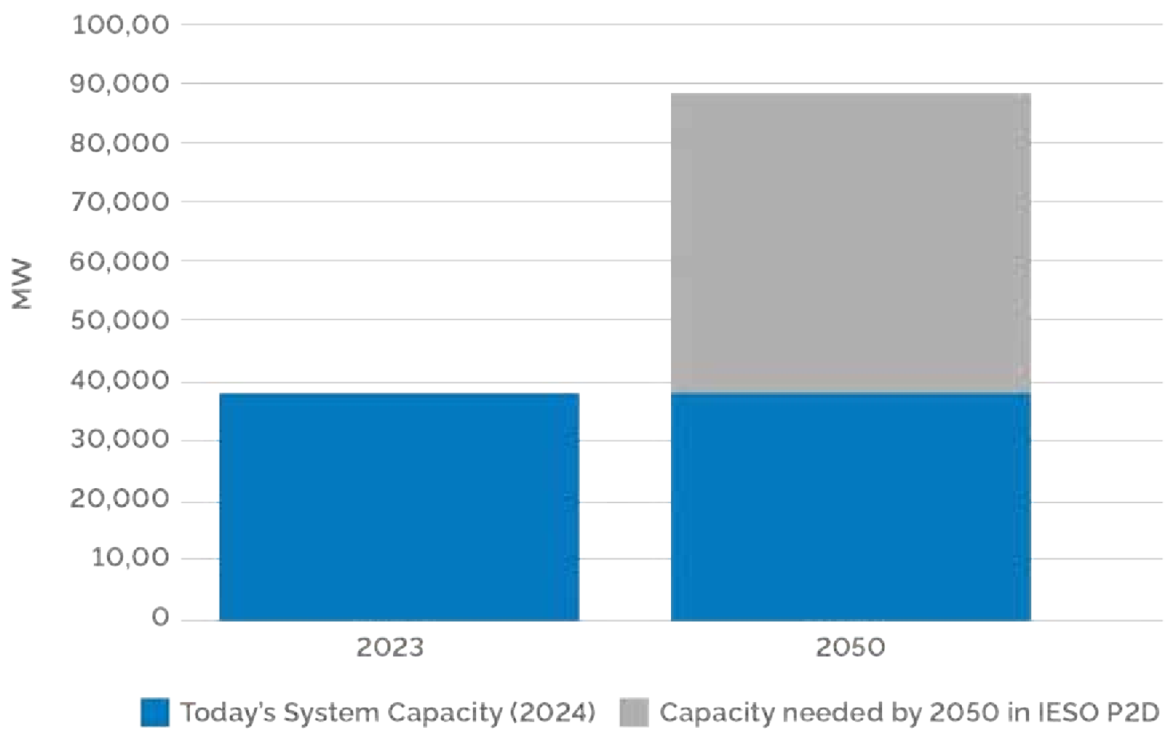
This is consistent with the expert advice of the system planners at the IESO whose Resource Eligibility Interim Report says: "Without a limited amount of new natural gas in the near term the IESO would be reliant on emergency actions such as conservation appeals and rotating blackouts to stabilize the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

Going Forward: Economic Growth and Electrification Driving Energy Demand

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

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

Figure 6: Ontario Electricity System Capacity 2024 vs. 2050



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

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

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

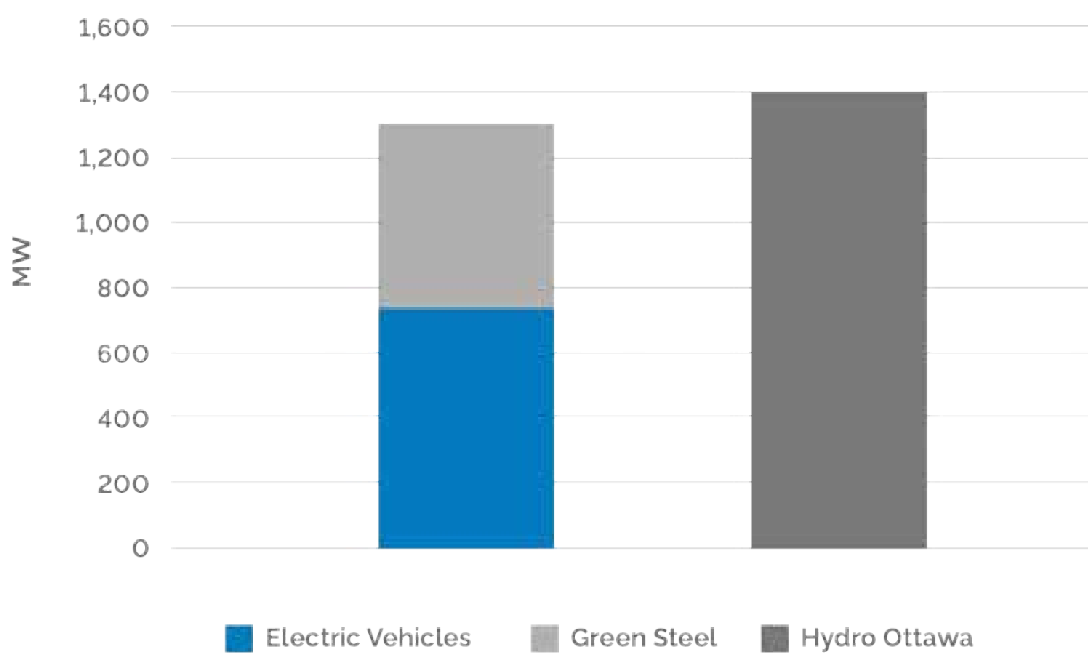
In April 2024, the government also welcomed a $15 billion investment by Honda Canada to create Canada's first comprehensive electric vehicle supply chain, located in Ontario.

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

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

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

Figure 7: Projected Industrial Electricity Demand



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

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

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

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

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

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

1. Planning for Growth

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

Introduction

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

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

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

Integrated Energy Resource Planning

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

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

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

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

Electrification and Energy Transition Panel

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

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

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

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

Priorities for Integrated Energy Resource Planning:

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

Electricity Generation

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

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

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

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

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

Priorities for Electricity Generation:

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

Electricity Transmission

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

Priorities for Electricity Transmission:

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

Last Mile Connections

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

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

Priorities for Last Mile Connections:

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

Natural Gas

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

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

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

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

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

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

Priorities for Natural Gas:

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

Other Fuels

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

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

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

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

Priorities for Other Fuels:

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

Indigenous Leadership and Participation

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

Canada's Largest Indigenous-Led Infrastructure Project

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

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

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

Priorities for Indigenous Leadership and Participation:

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

Local, Regional and Interjurisdictional Energy Planning

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

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

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

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

Priorities for Local, Regional and Interjurisdictional Energy Planning:

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

Growth-Oriented Agencies

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

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

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

Priorities to Support Growth-Oriented Agencies:

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

2. Affordable and Reliable Energy

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

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

Ontario's Alternative to a Carbon Tax

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

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

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

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

Priorities for Ontario's Alternative to a Carbon Tax:

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

Helping Ontarians Save through Energy Efficiency

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

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

Priorities for Helping Ontarians Save through Energy Efficiency:

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

Supporting Electric Vehicles (EVs)

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

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

Priorities for Supporting EVs:

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

Empowering Energy Consumers to Participate in the Grid

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

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

Priorities for Empowering Energy Consumers to Participate in the Grid:

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

Grid Modernization

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

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

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

Priorities for Grid Modernization:

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

Grid Resiliency

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

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

Priorities for Grid Resiliency:

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

Programs for Energy Affordability

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

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

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

Priorities for Programs for Energy Affordability:

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

Affordable Home Heating

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

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

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

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

Priorities for Affordable Home Heating:

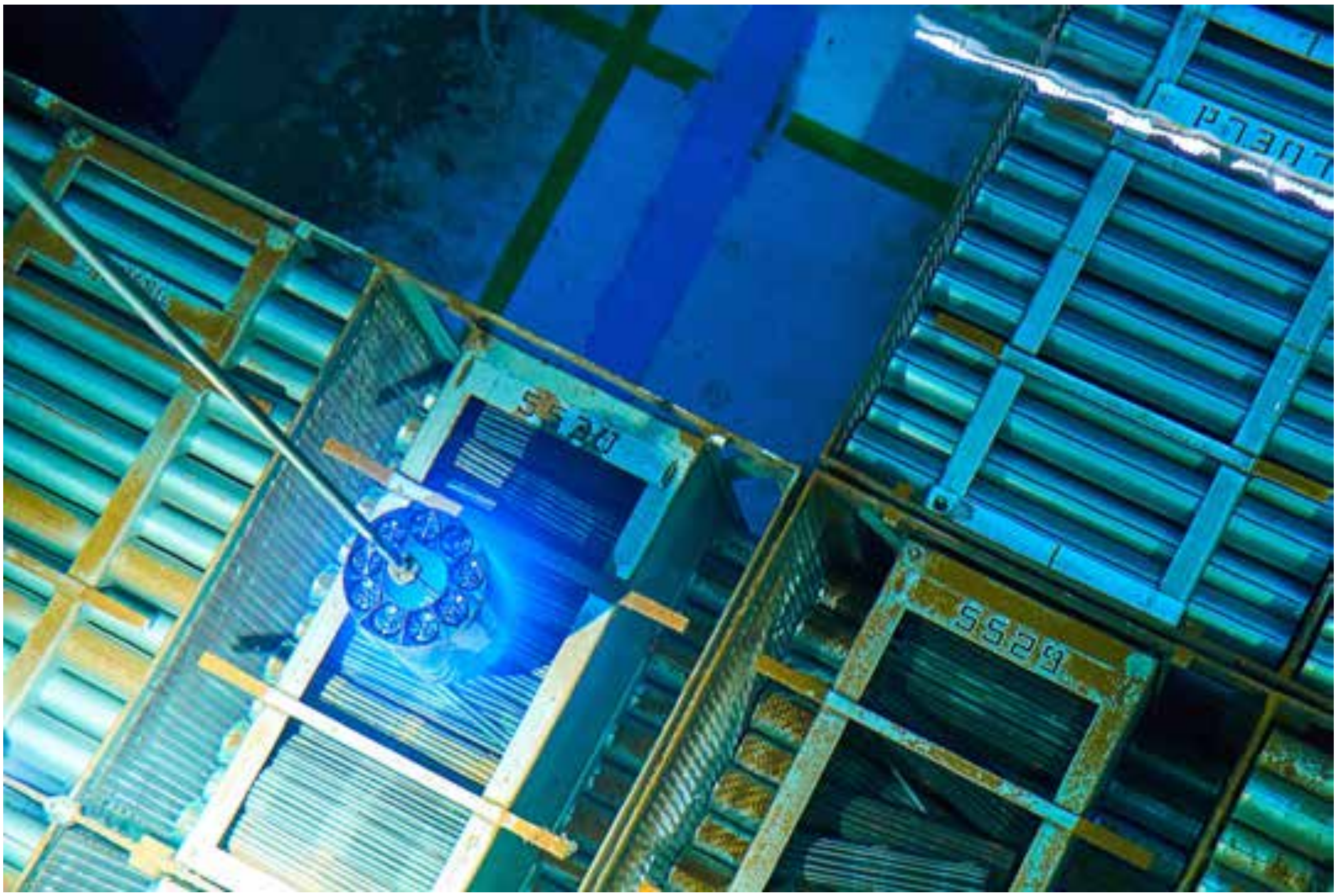
- There is a need to ensure Ontarians have affordable options for home heating from different energy sources.
- Affordable home heating options should be available that take advantage of Ontario's clean electricity system, such as through heat pumps and other new technologies as well as energy efficiency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

3. Becoming an Energy Superpower

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

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

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



Exporting Power and Expertise

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

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

History of Electricity Imports and Exports

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

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

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

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

Future Opportunities for Electricity Exports

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

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

The IESO's analysis will include:

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

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

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

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

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

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

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

Leadership in Nuclear Projects and Innovation

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

Priorities for Exporting Power and Expertise:

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

Next Steps

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

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

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

Glossary of Terms

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

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

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

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

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

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

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

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

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

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

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

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

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 20-80-B December 6, 2023

Investigation by the Department of Public Utilities on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals.

ORDER ON REGULATORY PRINCIPLES AND FRAMEWORK

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SUMMARY

The Department of Public Utilities ("Department") announces a regulatory framework intended to set forth its role and that of the Massachusetts gas local distribution companies ("LDCs") in helping the Commonwealth achieve its target of net-zero greenhouse gas ("GHG") emissions by 2050. Global Warming Solutions Act, St. 2008, c. 298 ("GWSA"); Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020). The Department seeks to enable the Commonwealth to move into its clean energy future while simultaneously safeguarding ratepayer interests and maintaining affordability for customers; ensuring safe, reliable, and cost-effective natural gas service; minimizing the burden on low- and moderate-income households as the transition proceeds; and facilitating a just workforce and energy infrastructure transition.

In this proceeding, the Department reviewed eight potential decarbonization "pathways" to achieving the target of a 90 percent gross reduction in GHG emissions by 2050 as compared to 1990 levels, as well as interim GHG emissions reductions targets of 50 percent by 2030 and 75 percent by 2040. The decarbonization pathways are designed to reflect different futures for the LDCs and their customers, ranging from ongoing use of the LDCs' distribution networks to 100-percent decommissioning of gas distribution infrastructure in the Commonwealth. The Department makes no findings as to a preferred pathway or technology; rather, our aim is to create and promote a regulatory framework that is flexible, protects consumers, promotes equity, and provides for fair consideration of the current and future technologies and commercial applications required to meet the Commonwealth's clean energy objectives.

The Department considered six regulatory design recommendations intended to facilitate the Commonwealth's transition: (1) support customer adoption of and conversion to electrified and decarbonized heating technologies; (2) blend renewable gas supply into gas-resource portfolios; (3) pilot and deploy innovative electrification and decarbonized technologies; (4) manage gas embedded infrastructure investments and cost recovery; (5) evaluate and enable customer affordability; and (6) develop LDC transition plans and chart future progress. The Department makes specific findings about each of these regulatory design recommendations as detailed in the Order.

As to supporting customer adoption of and conversion to electrified and decarbonized heating technologies, the Department finds that to achieve the Commonwealth's climate targets, there must be a significant increase in the use of electrified and decarbonized heating technologies. The Department and LDCs can play a pivotal role by enhancing incentives and expanding the Mass Save energy efficiency programs to facilitate customer use of heat pumps. The Department also addresses the critical need to minimize costs for customers, including through pursuit of outside funding sources, and prioritizing workforce development to enable a just transition framework for gas industry workers as well as customers.

The Department rejects the recommendation to change its current gas supply procurement policy to support the addition of renewable natural gas ("RNG") to LDC supply portfolios due to concerns regarding the costs and availability of RNG as well as its uncertain

status as zero-emissions fuel. The Department does support the option for customers to be able to purchase RNG from their LDC or a supplier at full cost to the customer.

Given the critical importance of significantly decarbonizing the heating sector, the Department considered the proposal that the LDCs pilot and deploy the following four technologies: (1) networked geothermal; (2) targeted electrification; (3) hybrid heating systems; and (4) renewable hydrogen. As detailed in the Order, the Department views networked geothermal projects as those with the most potential to reduce GHG emissions, and expresses support for targeted electrification as well.

The Department seeks to dissuade gas customer expansion and to align rate design with the Commonwealth's climate objectives. To achieve this, the Department instructs gas utilities to revise their per-customer revenue decoupling mechanism to a decoupling approach based on total revenues. Removing the incentive to add new customers aligns the LDCs' rate design with climate objectives and GHG emissions reductions targets. The Department finds it must examine the issue of depreciation, i.e., the period of time over which a capital investment is recovered, and stranded assets. As an initial step, the Department directs all LDCs to conduct a comprehensive review that includes a forecast of the potential magnitude of stranded investments, and to identify the impacts of accelerated depreciation proposals, as well as potential alternatives to accelerated depreciation.

The Department finds that consideration of non-gas pipeline alternatives ("NPAs"), defined broadly to include electrification, thermal networked systems, targeted energy efficiency and demand response, and behavior change and market transformation, is necessary to minimize investments in the gas pipeline system that may be stranded costs in the future as decarbonization measures are implemented. Going forward, the Department states that as part of future cost recovery proposals, LDCs will bear the burden of demonstrating that NPAs were adequately considered and found to be non-viable or cost prohibitive to receive full cost recovery.

The Department agrees with suggestions that the standards for investments to serve new customers be examined. The Department therefore directs the LDCs to begin reviewing existing tariffs, policies, and practices related to new service connections to determine: (1) the number of *de facto* free extension allowances; (2) whether current models and policies accurately reflect the anticipated income and timeframe over which the capital investments will be recovered; and (3) whether existing state policies are inconsistent with current practices by incentivizing new customers to join the gas distribution system and allowing LDCs to extend their systems through plant additions. Further, in reviewing future applications for new service, the Department will examine the appropriateness of the existing standard—that there be no adverse impacts on existing natural gas customers—in the context of a broader climate mandate.

The Department observes that there are numerous concerns regarding affordability for customers, including the upfront costs required for customers to convert appliances and heating systems from natural gas to electricity, and also higher rates for customers who remain on the system. Cost shifting between migrating and non-migrating customers and between rate classes, and potential disproportionate impacts on low-income customers and customers from environmental justice populations, present equity challenges as well.

Finally, the Department finds that the clean energy transition will require coordinated planning between LDCs and electric distribution companies, monitoring progress through LDC reporting, and aligning existing Department practices with climate targets. To that end, the Department orders LDCs to submit individual Climate Compliance Plans to the Department every five years beginning in 2025, and to propose climate compliance performance metrics in their upcoming performance-based regulation filings, ensuring a proactive approach to achieving climate targets.

I. INTRODUCTION

The Department of Public Utilities ("Department") opened this inquiry on October 29, 2020, to examine the role of Massachusetts gas local distribution companies ("LDCs") in helping the Commonwealth achieve its 2050 climate targets, and to identify strategies for enabling the Commonwealth to move into its net zero greenhouse gas ("GHG") emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth. Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals, D.P.U. 20-80, Vote and Order Opening Investigation at 1 (2020) ("Vote and Order"). The Department specifically sought to develop a regulatory and policy framework to guide the evolution of the gas distribution industry in the context of a clean energy transition that requires the Department to consider new policies and structures to protect ratepayers as the Commonwealth reduces its reliance on natural gas. D.P.U. 20-80, at 4. This proceeding is necessarily one step—not the first and certainly not the last—as we endeavor to chart a path forward that enables the Commonwealth to achieve its target of net zero GHG emissions by 2050. Global Warming Solutions Act, St. 2008, c. 298 ("GWSA"); Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020), available at https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download (last visited November 29, 2023). The Department docketed this matter as D.P.U. 20-80.

Through this investigation, the Department has gathered a significant body of information from the LDCs and a wide range of institutional and individual stakeholders, evincing the need for an evolving, multifaceted, broadly coalitional, and responsive process as we seek to define and meet the significant challenges and potential opportunities that are presented not only by the Commonwealth's climate targets, but also by the threat and reality of the climate crisis itself. The Department acknowledges and appreciates the time, commitment, and thoughtful contributions provided by many stakeholders throughout this proceeding. In this Order, we first enunciate a set of regulatory principles that will guide our decision-making in this and future dockets. We then address in more detail the reports and analyses produced by the LDCs and their consultants, as well the comments and analyses submitted by stakeholders. Our purpose here never has been to dictate one path forward, but to gather information and identify existing and potential means within our authority to remove barriers to the clean energy transition and find ways for the Department to facilitate and accelerate pursuit of our 2050 climate targets. To that end, in this Order we identify future areas of inquiry that will be explored and note those future proceedings (including technical conferences, adjudications, and additional investigations) where we will investigate and implement the issues and principles identified herein.

In enunciating regulatory principles, our intent is that these foundational propositions will inform many of the Department's processes and proceedings through a "whole of DPU" approach, not limited to those matters such as this where climate and GHG-reduction policies explicitly are at issue, but also inform rate design and other more traditional Department functions within our authority. We also note areas in which the Department cannot (or cannot yet) act unilaterally, observing where legislative change or other agency action is required as we seek to pursue vigorously our role in a "whole of government" response to the climate crisis. The Department is one governmental actor working toward the clean energy transition, and we anticipate necessary future legislative action, as well as implementation from the Executive Office of Energy and Environmental Affairs ("EEA"), Massachusetts Department of Energy Resources ("DOER"), Massachusetts Department of Environmental Protection ("MassDEP"), and the Massachusetts Clean Energy Center ("MassCEC"), among others. Finally, in establishing these guiding principles we take care to emphasize the role of communities, neighborhoods, and individuals within the clean energy transition, as we seek to facilitate active participation in a "whole of society" approach to electrification, decarbonization, a just and equitable workforce transition, and equitable investment in communities in pursuit of our 2050 climate targets. While the Department cannot dictate the choices of individual consumers, we can and will seek to maintain a safe, reliable, and affordable system while encouraging and facilitating the thousands of small transitions that must occur on household, neighborhood, and community levels for the Commonwealth as a whole to move into its clean energy future.

II. PROCEDURAL HISTORY

On October 29, 2020, the Department voted to open an investigation into potential policies that will enable the Commonwealth to reach its target of net zero GHG emissions by

2050 and the role of Massachusetts gas LDCs[1] in achieving that goal.[2] D.P.U. 20-80, at 1. The Department stated its intent to solicit utility and stakeholder input in this investigation, noting that EEA was (1) developing in consultation with MassDEP and DOER an evaluation of potential pathways to achieving the Commonwealth's 2050 GWSA statewide net zero emissions limit; and (2) preparing a Clean Energy and Climate Plan ("CECP")[3] for 2030. D.P.U. 20-80, at 3, citing Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020); G.L. c. 21N, §§ 3, 4; Massachusetts 2050 Decarbonization Roadmap (December 2020), available at

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1 The gas LDCs subject to the Department's jurisdiction are: The Berkshire Gas Company ("Berkshire Gas"); Boston Gas Company d/b/a National Grid ("National Grid (gas)"); Eversource Gas Company of Massachusetts ("EGMA") and NSTAR Gas Company ("NSTAR Gas"), each d/b/a Eversource Energy (together, "Eversource"); Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"); and Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty ("Liberty").

2 Prior to the Department's issuance of the Order, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a petition ("Petition") requesting that the Department open an investigation to assess the future of the LDCs' operations and planning in light of the Commonwealth's target of net zero GHG emissions by 2050 (Attorney General Petition at 1 (June 4, 2020), citing GWSA; Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020); State of the State Address (January 21, 2020)). The Attorney General's request has been incorporated into this docket.

3 EEA prepares a CECP every five years, beginning in 2010. The CECP sets forth a policy/roadmap for the Commonwealth to meet the GHG emissions limits by 2050. The Interim 2030 CECP developed by EEA was released in December 2020. The final CECP for 2025 and 2030 was released in June 2022 ("2025/2030 CECP") and can be found at https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030 (last visited November 29, 2023).

https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download (last visited November 29, 2023). The Department stated its anticipation that the 2050 Decarbonization Roadmap ("2050 Roadmap") and 2030 CECP (together, the "Roadmaps") would set forth policies affecting ratepayers, LDCs, and the gas industry as a whole. D.P.U. 20-80, at 3. The Department therefore directed the LDCs to: (1) initiate a joint request for proposals ("RFP") for an independent consultant to conduct a detailed study of each LDC and analyze the feasibility of all pathways identified in the Roadmaps, as well as any additional strategies identified by the independent consultant, to help the Commonwealth achieve its goal of net zero GHG emissions by 2050; (2) submit a report prepared by the independent consultant that integrates the individual analyses of each LDC into one, collective report containing comparisons among the LDCs; and (3) submit individual proposals to the Department that includes each LDC's recommendations and plans for helping the Commonwealth achieve its 2050 climate targets, supported by the independent consultant's report, along with all analyses and supporting data. The Vote and Order further directed that the LDCs engage in a stakeholder process to solicit feedback and advice on the independent consultant's report and the LDCs' individual proposals prior to submitting these documents to the Department. D.P.U. 20-80, at 4-5.

On November 6, 2020, the Attorney General filed a motion requesting clarification ("Motion for Clarification") of the Department's Vote and Order with respect to its directives for stakeholder participation in (1) the development of the RFP to hire an independent consultant; and (2) the Massachusetts gas LDCs' development of the report and proposals

(Attorney General Motion for Clarification at 1). The Department received several responses to the Attorney General's Motion for Clarification from interested stakeholders.[4] On February 10, 2021, the Department issued an order on the Attorney General's request. Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals, D.P.U. 20-80-A (2021).

On March 1, 2021, the Attorney General filed a notice of retention of experts and consultants in this investigation at funding not to exceed $150,000, filed pursuant to G.L. c. 12, § 11E(b) ("Notice of Retention"). On May 21, 2021, the Attorney General filed a revised notice to retain experts and consultants seeking an amended funding at an amount not to exceed $350,000 ("Revised Notice of Retention"). The Department received no comments on the Attorney General's Notice of Retention or Revised Notice of Retention[5] and on June 29, 2021, the Department issued an order approving the Attorney General's Revised

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4 The following stakeholders submitted responses to the Attorney General's Motion for Clarification: Conservation Law Foundation ("CLF"); the Sierra Club; Environmental Defense Fund ("EDF"); joint response by the gas LDCs; the Town of Hopkinton; the Gas Leaks Allies; and Mothers Out Front.

5 Pursuant to G.L. c. 12, § 11E(b), the Department must allow all full parties to a proceeding the opportunity to comment on the Attorney General's Notice of Retention. The only full party to this proceeding is the Attorney General. Nevertheless, the Attorney General served her Notice of Retention on the LDCs and the LDCs did not comment. It is unclear whether the Attorney General served her Revised Notice of Retention on the LDCs, but it was not required.

Notice of Retention. D.P.U. 20-80, Order on Attorney General's Revised Notice of Retention of Experts and Consultants (June 29, 2021).

On March 1, 2021, and September 1, 2021, and in accordance with the Department's directives, the LDCs provided status updates regarding the progress with respect to the RFP and stated that, through the RFP, the LDCs selected Energy & Environmental Economics ("E3"), with ScottMadden as subcontractor (together, "Consultants"), to be the independent consultant for the pathways analysis, and the retention of Environmental Resources Management ("ERM") to develop and facilitate the stakeholder process.

On March 18, 2022, pursuant to the Department's Vote and Order, each LDC submitted: (1) the company's individual proposals and plans for helping the Commonwealth achieve its 2050 climate targets within reports entitled "net zero enablement plan[s]" ("Net Zero Enablement Plan," or collectively, "Net Zero Enablement Plans"); and (2) a report on the technical analysis of decarbonization pathways ("Pathways Report") as well as a report on considerations and alternatives for regulatory designs to support transition plans ("Regulatory Designs Report") (collectively, the "Reports").[6] In addition, on this same date the LDCs submitted: (1) a stakeholder engagement report ("Stakeholder Engagement Report") prepared by ERM to develop and facilitate the stakeholder engagement process; (2) the gas LDCs' common regulatory framework and overview of the Net Zero Enablement

6 The Reports were prepared by the LDCs' Consultants.

Plans ("Framework and Overview"); and (3) a proposed Net Zero Enablement Plan model tariff ("Model Tariff").

On March 23, 2022, the Department issued a Notice of Filing, Public Hearing, and Request for Comments ("Notice") along with an Order of Notice ("Order of Notice").[7] The

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[7] On February 14, 2022, the Attorney General and DOER submitted correspondence outlining procedural recommendations, including a proposed procedural schedule for this matter, for which CLF, National Consumer Law Center ("NCLC"), Low-Income Energy Affordability Network ("LEAN"), and Home Energy Efficiency Team ("HEET") expressed support. In consideration of the recommendations submitted by the Attorney General and DOER, the Department set a procedural schedule in this matter on March 24, 2022.

On March 28, 2022, CLF, Acadia Center, EDF, HEET, and Sierra Club jointly filed a motion for reconsideration of the Department's Order of Notice issued on March 23, 2022 ("Joint Motion for Reconsideration"). The Joint Motion for Reconsideration requested that the Department: (1) rescind its March 23, 2022 Order of Notice; (2) extend the procedural schedule set forth by the Department on March 24, 2022; and (3) allow for additional process in this docket, including the opportunity to intervene or otherwise obtain party status, participate in discovery, present expert testimony, and to cross-examine witnesses (Joint Motion for Reconsideration at 11-12).

On April 4, 2022, the Department received a jointly filed response by the gas LDCs ("LDCs' Response to Joint Motion for Reconsideration") objecting to the Joint Motion for Reconsideration on the grounds that (1) the Joint Motion for Reconsideration is improper and contradictory to the purposes of this proceeding and (2) the process outlined in the Department's Notice and procedural schedule is consistent with both Department precedent for similar proceedings and the Attorney General's Petition in this matter (LDCs' Response to Joint Motion for Reconsideration at 3-4).

On April 15, 2022, the Department issued a Hearing Officer Memorandum noting that pursuant to the Notice of Filing and Public Hearing issued in this matter, the deadline for submitting written comments was May 6, 2022. The Department encouraged stakeholders to submit comments identifying issues with the consultants' reports and the LDCs' individual proposals and suggestions and recommendations of alternative

Department held technical sessions on the Reports and Net Zero Enablement Plans on March 30, 2022, and April 15, 2022. On May 3, 2022, and May 5, 2022, the Department held public hearings to receive comments on the Reports and Net Zero Enablement Plans.

The Department received more than 230 initial comments from various stakeholders and members of the public ("Initial Comments"). The Department directed the gas LDCs to respond to the Initial Comments, and the LDCs submitted their response on July 29, 2022 ("LDC Joint Comments"). On September 8, 2022, the Department requested all final comments from stakeholders in response to the LDCs' Joint Comments by October 14, 2022 ("Final Comments").[8, 9]

The Department issued seven sets of common information requests to the gas LDCs, one set of information requests each to Berkshire Gas and Unitil, and two sets of information

proposals, particularly alternative regulatory framework proposals (Hearing Officer Memorandum at 2 (April 15, 2022)). The Department stated that its goal is to develop an overall regulatory framework that will be used to guide statewide and company-specific proposals, so the Department specifically sought alternative proposals that will inform the Department's analysis on the regulatory framework. The Department further stated its intent to schedule additional technical conferences to explore regulatory framework proposals after the May 6, 2022 comment deadline (Hearing Officer Memorandum at 2 (April 15, 2022)).

8 The substance of the Initial Comments, LDC Joint Comments, and Final Comments is discussed further below in Sections V and VI.

9 DOER submitted late-filed Final Stakeholder Comments on October 17, 2022, pursuant to its request to submit its final comments one business day late. The Department herein accepts DOER's late-filed Final Stakeholder Comments.

requests each to Eversource, Liberty, and National Grid (gas). In total, the Department issued 113 information requests to the LDCs.

III. BEYOND GAS: A SUMMARY OF REGULATORY PRINCIPLES

Massachusetts has long been a national leader in adopting state policies to address climate change. Through our actions in this proceeding, we continue in that leadership role by tackling the challenging issues associated with developing a pathway for the transition in the natural gas industry that will be necessary for the Commonwealth to achieve its target of net-zero GHG emissions by 2050, as set forth in the GWSA, and to achieve the sector-specific emissions reductions established in the CECP for 2025 and 2030.[10]

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[10] In addition to the GWSA, the Commonwealth has enacted An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8 ("2021 Climate Act"), and An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179 ("2022 Clean Energy Act"). The GWSA, as amended by the 2021 Climate Act and implemented by the Secretary of EEA, requires the Commonwealth to reduce GHG emissions between 10 and 25 percent from 1990 levels by 2020, at least 50 percent from 1990 levels by 2030, at least 75 percent from 1990 levels by 2040, and achieve net-zero emissions by 2050 with a gross reduction in emissions of 85 percent from 1990 levels. G.L. c. 21N § 4; Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020) (setting a legally binding statewide limit of net-zero GHG emissions by 2050, defined as 85 percent below 1990 levels); State of the State Address (January 2021) (Governor commits to achieving net zero greenhouse gas emissions by 2050), available at https://archives.lib.state.ma.us/handle/2452/816469 (last visited November 29, 2023). The CECP for 2025 and 2030 set sector-specific emissions reduction targets, as mandated by the 2021 Climate Act, setting an emissions reduction target for residential heating and cooling of 29 percent by 2025 and 49 percent by 2030 and an emission reduction target for commercial and industrial heating and cooling of 35 percent by 2025 and 49 percent by 2030 (2025/2030 CECP at 23). The 2025/2030 CECP and supporting information including sublimits is available at https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030 (last visited November 29, 2023).

As we chart the path for this transition, we emphasize that nothing we do here is intended to jeopardize the rate recovery of the billions of dollars of existing investments in natural gas infrastructure by the LDCs operating within the Commonwealth. Traditional notions of the regulatory compact continue to apply to those investments and, accordingly, there generally must be some demonstration of imprudence before recovery of existing investments can be challenged. At the same time, however, it is fair to say that a different lens will be applied to gas infrastructure investments going forward. The Department will be examining more closely whether such additional investments are in the public interest, given the now-codified commitment toward achieving Commonwealth's target of achieving net-zero GHG emissions by 2050 and the urgent need to address climate change. In this "beyond gas" future, we will be exploring and implementing policies that are geared toward minimizing additional investment in pipeline and distribution mains and achieving decarbonization in the residential, commercial, and industrial sectors.

The ambitious mandates established by the Commonwealth require gas LDCs to move beyond "business as usual" in their gas system planning, whether involving proposed expansion of service to new areas or investments necessary to maintain the safety of existing natural gas infrastructure. As discussed in subsequent sections of this Order, we are acting, within our existing statutory authority, to discourage further expansion of the natural gas distribution system. We will do so by revisiting the "public interest" standard we apply in evaluating proposed expansions, by examining the line extension policies followed by LDCs that may be inconsistent with the broader public policy of achieving necessary GHG reductions, and by encouraging consideration of zero-carbon alternatives, such as electrification and thermal networked systems, to traditional gas system capital investments.

With respect to maintenance of the existing natural gas infrastructure, our "beyond gas" future will similarly involve close scrutiny of the extent to which additional investment is necessary, with an eye toward minimization of costs that may be stranded in the future as decarbonization measures are implemented in the natural gas industry. In particular, we will generally require the examination of non-gas pipeline alternatives ("NPAs"), defined broadly to include electrification, thermal networked systems, targeted energy efficiency and demand response, and behavior change and market transformation.[11] Going forward, LDCs will have the burden to demonstrate the consideration of NPAs as a condition of recovering additional investment in pipeline and distribution mains. As discussed in later sections of this Order, we will continue to explore opportunities for strategic and targeted decommissioning of portions of LDC service territories, through demonstration projects deploying both electrification and thermal network technologies.

As in the case of the transition to clean energy in the electricity sector, the decarbonization of the natural gas industry may result in higher costs being imposed on ratepayers. Given the urgency of addressing the climate crisis, however, we are reluctant to slow the pace at which the transition must occur due to concerns about affordability for

11 The comprehensive analysis of NPAs that we envision incorporates many of the elements identified in the Attorney General's proposed "investment alternatives calculator" and the "geographic marginal cost analysis" proposed by DOER, both of which are discussed later in this Order.

low- and moderate-income utility customers. Rather, the Department will address these issues in a separate proceeding, to be commenced later this year, dedicated toward examining innovative solutions to address the energy burden and affordability, such as capping energy bills by percentage of income or offering varying levels of low-income discounts, that have been implemented in other jurisdictions. We are confident that we can develop a solution—which likely will require a change in our statutory authority—that will allow us to address affordability issues in an effective manner and still enable us to achieve the necessary progress toward the Commonwealth's GHG emission reduction limits.

The transition of the natural gas industry involves other important considerations that we will need to address in a thoughtful and deliberate manner. As the Commonwealth accomplishes greater penetration of building electrification and distributed energy resources, we need to prioritize opportunities for residents of environmental justice populations[12] to benefit from moving beyond gas. This includes electrification and thermal network projects as well as workforce development and employment prospects for people historically left out

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[12] In Massachusetts, an environmental justice population is a neighborhood where one or more of the following criteria are true: (1) the annual median household income is 65 percent or less of the statewide annual median household income; (2) people of color make up 40 percent or more of the population; (3) 25 percent or more of households identify as speaking English less than "very well"; (4) people of color make up 25 percent or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150 percent of the statewide annual median household income. Executive Office of Energy and Environmental Affairs Environmental Justice Policy at 4 (2021). See https://www.mass.gov/info-details/environmental-justice-populations-in-massachusetts (last visited November 29, 2023).

of the clean energy transition (e.g., women, people of color, Indigenous Peoples, veterans, people living with disabilities, immigrants, people who were formerly incarcerated). We also will work with the LDCs to encourage workforce development training and employment opportunities for gas workers and steelworkers to participate in a just transition away from fossil fuels. Thermal network projects, for example, offer attractive opportunities for workers in the gas industry to perform similar work in the installation of the infrastructure to deliver decarbonized heating and cooling solutions to residential and commercial customers.

Finally, as is apparent from the vast number of issues addressed in this Order, developing a regulatory framework to guide the transition of the natural gas industry in Massachusetts is an exceedingly complex undertaking. It involves fundamental ratemaking issues regarding the continued financial viability of LDCs and preserving their ability to raise capital on reasonable terms, as well as developing an orderly means of recovering in rates the billions of dollars in existing investment in natural gas infrastructure while maintaining the safety of the gas distribution system so long as natural gas continues to be delivered through it. It involves maintaining the affordability of energy services, and being particularly mindful to avoid burdening low- to moderate-income households that may be left behind—and potentially bearing a greater burden of the fixed costs of maintaining existing natural gas infrastructure—as more affluent households transition away from natural gas appliances. It involves recognizing the potential for the disproportionate distribution of the negative impacts associated with building, operating, and maintaining gas infrastructure. And it involves addressing the workforce issues associated with a gradual decommissioning of the existing natural gas distribution system. As we continue to develop the regulatory framework in subsequent proceedings following the issuance of this Order, we emphasize the importance of the continued involvement of all relevant stakeholders in the process. It is important, for example, for LDCs to move beyond "business as usual" practices toward active participation in developing innovative solutions to achieving the clean energy future codified in the Commonwealth's GHG emissions reduction targets. These exceedingly complex issues can be addressed effectively only with the broad participation of all the constituencies affected by this transition. We look forward to exploring these issues collectively in future proceedings.

IV. SCOPE AND AUTHORITY

The Department has broad authority to supervise gas companies pursuant to G.L. c. 164, § 76; Massachusetts Electric Company v. Department of Public Utilities, 419 Mass. 239, 245 (1994). It is well established, however, that the Department's general supervisory authority cannot arise from a vacuum. Massachusetts Oilheat Council, Inc., D.T.E. 00-57, at 6-7 (2001) citing Massachusetts Electric Company, 419 Mass. at 246.

The Legislature has taken steps to focus the Department's regulatory mandate on GHG emissions reductions in addition to its traditional concerns of ensuring safety, security, reliability, equity, and affordability. Both the 2021 Climate Act and 2022 Clean Energy Act include changes to the Department's regulatory authority over gas companies. In the 2021 Climate Act, the Legislature added Section 1A to G.L. c. 25, which provides:

> In discharging its responsibilities under [chapter 25] and chapter 164, the department shall, with respect to itself and the entities it regulates, prioritize safety, security, reliability of service, affordability, equity and reductions in

> greenhouse gas emissions to meet statewide greenhouse gas emission limits and sublimits established pursuant to chapter 21N.

The 2021 Climate Act also revised G.L. c. 21N, § 6, to charge the Secretary of EEA with establishing programs to meet GHG emissions limits and sublimits and implement the roadmap plans established by G.L. c. 21N. In addition, the 2022 Clean Energy Act amended G.L. c. 164, § 141, which now directs the Department, in all decisions or actions regarding rate designs, to consider, among other things, the impact of such decisions or actions on the reduction of GHG emissions as mandated by G.L. c. 21N to reduce energy use.

Recent legislation has not, however, amended or repealed other statutes that govern the Department's regulation of the natural gas industry. As we note in this Order, the Department may revisit its own precedent and standards of review in certain areas, and in other areas, legislative action may be required for the Department to be able to implement change or pursue particular pathways for achieving the Commonwealth's 2050 targets. For example, G.L. c. 164, § 30, establishes Department review of an LDC's petition to expand its service territory, which the Department has evaluated under a public interest standard. An Act Relative to Gas Leaks, St. 2014, c. 149, was enacted on June 26, 2014 ("Gas Leaks Act") and codified the uniform gas leaks classifications at G.L. c. 164, § 144; gas system enhancement plans ("GSEPs") at G.L. c. 164, § 145; and required the Department to, on or before January 1, 2015, authorize gas companies "to design and offer programs to customers which increase the availability, affordability, and feasibility of natural gas service for new customers." St. 2014, c. 149, § 3. In addition, the 2022 Clean Energy Act mandates that DOER establish a demonstration project in which up to ten municipalities may adopt zoning ordinances that restrict fossil fuel use in the construction sector. St. 2022, c. 179, § 84(b). As part of the demonstration project, DOER must collect data from the participants and submit reports to the Legislature every two years that include recommendations for the continuation or termination of the demonstration project. St. 2022, c. 179, § 84(e).

Finally and most specifically to our consideration of the Reports, Net Zero Enablement Plans, and other submissions in this proceeding, Section 77 of the 2022 Clean Energy Act provides:

> Notwithstanding any general or special law or rule, regulation or order to the contrary, the department of public utilities shall not approve any company-specific plan filed pursuant to the DPU Docket No. 20-80, Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals, prior to conducting an adjudicatory proceeding with respect to such plan.

St. 2022, c. 179, § 77. Based on this clear directive, the Department will not approve the Net Zero Enablement Plans and/or the Model Tariff submitted by the LDCs in this investigation but will identify future adjudicatory proceedings and filings where we may properly consider company-specific plans.

The Department does not cite the above statutes as obstacles to the regulatory principles articulated in this Order. Rather, we do so only to acknowledge that our authority as a regulatory agency is bound by the limits established by law. Where pathways or proposals are inconsistent with existing statutes, the Department will note where additional legislative change or authority is necessary.

V. DECARBONIZATION REPORTS

A. Pathways to Net Zero

At the direction of the Department, the LDCs retained the Consultants to perform a detailed study for each LDC, analyzing the feasibility of each decarbonization pathway identified by the Roadmaps. D.P.U. 20-80, at 3-5. In an effort to allow for meaningful comparisons among the LDCs and to ensure the consideration of all decarbonization strategies, the Department required the Consultants to identify any pathways not examined in the Roadmaps and employ consistent methods and considerations to analyze decarbonization opportunities for each individual LDC. D.P.U. 20-80, at 5. The Department instructed the Consultants to combine the individual analyses into a single, collective report presenting: (1) a quantification of the costs and actual economy-wide GHG emissions reductions involved in transitioning the natural gas system; and (2) a discussion of qualitative factors such as impacts on public safety, reliability, economic development, equity, emissions reductions, and timing for each identified pathway, among other requirements. D.P.U. 20-80, at 5-6.

To fulfill this requirement, the LDCs submitted the Pathways Report, which provides eight pathways designed to reflect different futures[13] for the LDCs and their customers

13 The eight pathways are not forecasts, but rather narratives that allow for the identification and comparison of the relative costs, risks, and feasibility of different futures (Pathways Report at 11, 34). The Pathways Report further notes that analyzing decarbonization pathways out to 2050 involves a multi-decade horizon that is inherently assumption-driven and uncertain across several factors, including cost, consumer behavior, technology development, deployment, and other factors (Pathways Report at 27).

(Pathways Report at 11). Each of the eight pathways achieves the Commonwealth's goals of 90 percent gross GHG emissions reductions and net-zero GHG emissions by 2050 compared to 1990 levels, as well as the interim statutory GHG emissions reduction goals of 50 percent by 2030 and 75 percent by 2040 (Pathways Report at 11, 48). Similar to the 2050 Roadmap, all pathways have approximately 4.5 million metric tons of gross economy-wide, non-energy emissions[14] remaining in 2050 (Pathways Report at 48).

The eight pathways include the deployment of seven space-heating technologies,[15] and leverage various levels of renewable fuels, energy efficiency,[16] and building electrification technologies (Pathways Report at 31, 49-57). The eight decarbonization pathways impute a range of uses and roles for the gas system over time, spanning from 100 percent decommissioning of the system to large amounts of renewable gases being supplied to high-efficiency gas appliances (Pathways Report at 11, 63-75). In parallel, the Pathways

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14 A more detailed description of GHG accounting (i.e., direct, electric sector, non-energy, and renewable fuels emission accounting methods) can be found in the Pathways Report, Appendix 1, at 21-28. Further information on common baseline economy-wide assumptions such as population growth and electrification of the transportation sector can be found in the Pathways Report, Appendix 1, at 8-9.

15 The seven identified space-heating technologies include: (1) air source heat pumps; (2) ground source heat pumps; (3) hybrid heat pumps; (4) networked geothermal; (5) standard gas furnaces; (6) high efficiency gas furnaces; and (7) gas heat pumps (Pathways Report at 31).

16 The Pathways Report states that energy efficiency is a foundational strategy to enable decarbonization of heating across all scenarios, reducing challenges associated with both electrification and decarbonized fuel-based strategies (Pathways Report at 47, 52-53, 110).

Report considers impacts on the electric system due to electrification-driven peaks and increased generation capacity (Pathways Report at 57-63).

The Pathways Report notes several key uncertainties across the pathways and develops sensitivity analyses to better capture assumptions in its modeling (Pathways Report at 34-35). Informed by a literature review,[17] the Pathways Report provides both optimistic and conservative views for the following six uncertainties: (1) incremental costs of cold-climate air source heat pumps ("cold-climate ASHPs"); (2) technical performance of cold-climate ASHPs; (3) incremental electric sector distribution system costs; (4) networked geothermal system installation costs; (5) cost and availability of renewable fuels;[18] and (6) opportunities for gas system cost avoidance (Pathways Report at 35). Additionally, the Pathways Report projects three pathways that would involve gas system departures through a geographically planned approach,[19] resulting in potential reductions in operation and maintenance expenses,

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17 The Consultants conducted a literature review of decarbonization strategies studied and implemented in the U.S. and internationally (Pathways Report at 28-29; App. 2).

18 The Pathways Report defines renewable fuels as an umbrella term for renewably produced alternatives to fossil fuels, inclusive of renewable gases in the distribution system and renewable fuels in the transportation sector (Pathways Report at 9). The Report designates the following gases as renewable and having a net–zero GHG impact according to the Massachusetts GHG Inventory: (1) biomethane produced through anaerobic digestion or gasification; (2) hydrogen produced from electrolysis powered by renewable energy; and (3) synthetic natural gas produced from renewable hydrogen and a climate-neutral source of carbon (Pathways Report at 9, 52, 110; App. 1, at 21-22). The Department does not necessarily consider biomethane, hydrogen, or synthetic natural gas to be renewable fuels.

19 The Department further discusses geographically planned approaches and customer choice topics below in Section VI.B and Section VI.D.

GSEP expenditures,[20] and capital replacement costs (Pathways Report at 68-69). The Pathways Report further explores the cost and equity implications of combining the revenue requirement for the LDCs to maintain and operate both the gas and a networked geothermal system (Pathways Report at 72-75).[21]

The Pathways Report states that three pathways were modified from the Roadmaps: (1) high electrification, in which greater than 90 percent of the building sector electrifies primarily through the adoption of cold-climate ASHPs; (2) low electrification, in which 65 percent of the building sector electrifies with cold-climate ASHPs and gas customer count declines by 40 percent compared to today; and (3) interim 2030 CECP, in which the building sector electrifies at an accelerated pace, following the goals outlined in the Interim 2030 CECP (Pathways Report at 29-31). The 100 percent gas decommissioning pathway assumes that the building and industrial sectors fully electrify by 2050, with roughly 25 percent of the building sector converting to networked geothermal (Pathways Report at 31). The targeted electrification pathway assumes that greater than 90 percent of buildings electrify, with LDC customers converting to cold-climate ASHPs in a targeted approach (Pathways Report at 31). The networked geothermal pathway considers roughly 25 percent of the building sector

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[20] The Department allows LDCs to recover certain costs associated with the replacement of leak-prone pipeline infrastructure, pursuant to G.L. c. 164, § 145.

[21] The Pathways Report posits that a combined rate base would exhibit increased system costs, but theoretically would mitigate costs per customer as a larger portion of the customers remain that may share in the recovery of the combined system costs (Pathways Report at 73-75).

converting to networked geothermal systems, with remaining LDC customers using renewable gas[22] (Pathways Report at 31). The hybrid electrification[23] pathway assumes that greater than 90 percent of buildings electrify through cold-climate ASHPs paired with RNG (Pathways Report at 31). Lastly, the efficient gas equipment scenario assumes that the building sector largely adopts high-efficiency gas appliances supplied by a combination of renewable gas, with the industrial sector converting to dedicated hydrogen pipelines (Pathways Report at 31). Table 1 below contains a summary of each decarbonization pathway.

Table 1: Key Narratives by Decarbonization Pathway (Pathways Report at 29-32)

Pathway	Overview
Low Electrification (inspired by 2050 Decarbonization Roadmap "Pipeline Gas")	High electrification in the transportation sector. Buildings partly electrify. Building sector electrifies 65 percent of buildings through the adoption of ASHPs. Gas customer count declines by 40 percent compared to today.
High Electrification (inspired by 2050 Decarbonization Roadmap "All Options")	High electrification in both buildings and transportation sector. Building sector electrifies more than 90 percent primarily through the adoption of ASHPs.
Interim 2030 CECP	Accelerated electrification and building shell measures based on the interim 2030 building sector target.

22 The Pathways Report defines "renewable gas" as "an umbrella term referring to renewably produced alternatives to natural gas that can be blended into the distribution pipeline system" (Pathways Report at 9, App. 1, at 15). Under this definition, renewable gases include biomethane produced through anaerobic digestion or gasification, renewable hydrogen, and synthetic natural gas ("SNG"), further defined and discussed in Section VI.C of this Order (Pathways Report at 9, App. 1, at 15).

23 The Pathways Report describes hybrid electrification as a space heating strategy that combines electric heat pumps with a gas or fuel oil backup that can be powered by renewable fuels (Pathways Report at 8).

Hybrid Electrification	Heat pumps are paired with gas or fuel oil backup to mitigate electric sector impacts. More than 90 percent of buildings electrify through ASHPs paired with renewable gas back-up (hybrid heat pumps) that supply heating in cold hours of the year.
Networked Geothermal	Part of the gas system is strategically replaced by networked geothermal systems. LDCs evolve their business model and convert +/- 25 percent of the building sector to networked geothermal systems. Remaining gas customers use renewable gas as their main source of heating by 2050.
Targeted Electrification	Part of the gas system is strategically decommissioned with customers adopting ASHPs. More than 90 percent of buildings are electrified through a combination of technologies. LDC customers converting to ASHPs do so in a "targeted" approach.
Efficient Gas Equipment	Building sector will adopt increasingly efficient gas appliances supplied by decarbonized gas. The industrial sector converts to dedicated hydrogen pipelines.
100 Percent Gas Decommissioning	Building sector and industry will fully electrify allowing for 100 percent decommissioning of the gas distribution system. Building and industrial sectors fully electrify by 2050. +/- 25 percent of the building sector converts to networked geothermal systems.

Developed with input from both LDCs and stakeholders, the eight pathways and their associated projected cumulative energy system costs (in 2020 dollars)[24] are calculated as follows: (1) high electrification, \$87 billion to \$111 billion; (2) low electrification, \$73 billion to \$95 billion; (3) interim 2030 CECP, \$93 billion to \$121 billion; (4) 100 percent gas decommissioning, \$94 billion to \$135 billion; (5) targeted electrification,

24 The Pathways Report calculates costs on a levelized basis, including a society-wide discount factor of 3.6 percent, noting that the study does not quantitatively consider the social costs of carbon or avoided costs related to potential health or environmental damages resulting from climate change (Pathways Report, App. 1, at 62).

$73 billion to $109 billion; (6) networked geothermal, $81 billion to $124 billion; (7) hybrid electrification, $63 billion to $92 billion; and (8) efficient gas equipment, $66 billion to $105 billion (Pathways Report, App. 1, at 62-65). The Pathways Report further presents cumulative energy system costs both annually and by decade relative to a reference scenario that does not meet the Commonwealth's 2050 climate targets, delineating the following cost components: (1) demand-side capital; (2) electricity supply; (3) gas system; (4) natural gas commodity costs; (5) liquid renewable fuels commodity costs; (6) renewable gas commodity costs; and (7) networked geothermal installation costs (Pathways Report at 13-14, 26-27, 79-82; App. 1, at 62, 65-66).

Further, the Pathways Report offers an evaluation of the feasibility and level of challenge[25] expected for each pathway across the following criteria: (1) cumulative energy system costs; (2) technology readiness; (3) air quality; (4) workforce transition; (5) customer practicality; (6) near-term customer affordability; (7) long-term customer affordability; and (8) customer equity (Pathways Report at 11-12, 76-79, 84-108). The Pathways Report states that all pathways were assumed to comply with Department and industry standards for safety and reliability (Pathways Report at 11-12, 77, 87-91).

Lastly, the Pathways Report presents several low-regret strategies and commonalities across the LDCs, while highlighting the need for further research and development ("R&D")

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[25] The Pathways Report defines challenge as the magnitude of change from current industry or customers practices and/or amount of policy intervention required (Pathways Report at 76).

and key distinctions among the LDCs (Pathways Report at 109-115). In conclusion, the Pathways Report finds that all pathways imply transformational changes for the Commonwealth, the LDCs, and their customers, and that strategies that use both the gas and electric systems to deliver low-carbon heat to a portion of the buildings in Massachusetts show a lower level of challenge across a range of evaluation criteria (Pathways Report at 11, 109).

B. Stakeholder Comments Concerning the Pathways Report

Many commenters disagree with the Pathways Report's conclusion that pathways utilizing both the gas and electric systems actually would present a lower level of challenge to the Commonwealth in reaching its climate commitments. For example, the Attorney General contends that the lower overall costs reported for the hybrid electrification pathway rest on unsound and unproven assumptions, arguing that the beneficial impacts of hybrid electrification on electric system infrastructure additions could be attained by focusing on building electrification in the near term. (Attorney General Technical Comments[26] at 6-8, 19-21 (May 6, 2022)). Although DOER acknowledges significant alignment between the Pathways Report and the 2050 Roadmap, DOER calls on the Department to acknowledge that electrification is the dominant strategy specified in the 2025/2030 CECP, and to find that the LDCs' proposed plans and framework are not sufficient to achieve decarbonization (DOER

26 The Office of the Attorney General's Initial Stakeholder Comments on Consultants' Technical Analysis of Decarbonization Pathways Report (May 6, 2022).

Comments at 6-7 (May 6, 2022) ("DOER Initial Comments"); DOER Comments at 6-8 (October 17, 2022) ("DOER Final Comments")).

Other commenters opine that electrification should not be the Commonwealth's sole decarbonization strategy, arguing that hybrid pathways are necessary for preserving optionality as renewable generation increasingly comes online (see, e.g., Associated Industries of Massachusetts ("AIM") Comments at 2 (June 17, 2022); Shell USA, Inc. Comments at 4-5 (May 6, 2022); Tufts Medicine Lowell General Hospital Comments at 1 (July 22, 2022); Lahey Hospital and Medical Center Comments at 1 (July 15, 2022); SFE Energy Massachusetts, Inc. ("SFE Energy") Comments at 3 (May 6, 2022)). Similarly, the National Fuel Cell Research Center calls for further quantification of the value of the increased reliability and resilience that could be provided by decarbonized gas and electric systems (National Fuel Cell Research Center Comments at 2 (May 6, 2022)).

Numerous commenters criticize the Pathways Report's assumptions regarding the availability, pricing, and emissions of renewable fuels (see, e.g., Attorney General Technical Comments at 8-19; Sierra Club Comments at 8-9 (May 6, 2022) ("Sierra Club Initial Comments"); Acadia Center Comments at 7-15 (May 6, 2022) ("Acadia Center Initial Comments")). The Attorney General notes that the annual volumes of RNG needed in Massachusetts by 2050 under a hybrid electrification pathway is roughly 70 trillion British thermal units ("TBtu"), whereas the total available RNG output nationwide as of 2020 was only 50 TBtu (Attorney General Technical Comments at 9). The Attorney General argues that both the exponential growth in RNG volumes and the practicality of Massachusetts securing a population-weighted "fair share" of 3.7 percent of all RNG volumes east of the Mississippi River are unrealistic (Attorney General Technical Comments at 9-12; Attorney General Final Comments at 20-21 (October 14, 2022)). Several other commenters question the availability and market clearing price of RNG modeled under the hybrid electrification pathway (see, e.g., Sierra Club Initial Comments at 10-12; Acadia Center Initial Comments at 10-15).

Relatedly, several commenters argue that the Pathways Report repeats known flaws in Massachusetts GHG Inventory[27] accounting, questioning whether renewable fuels are truly carbon neutral when combusted, and if upstream emissions related to the extraction and transmission of fuels should be counted (see, e.g., Acadia Center Initial Comments at 4-10; Sierra Club Initial Comments at 8; LexCAN Advocacy Committee Comments at 1 (May 9, 2022)). Some commenters question the leakage rates associated with the existing gas system, demanding greater transparency regarding leakage rates and lost and unaccounted for gas volumes (see, e.g., "Interested Persons"[28] Comments at 2-4; CLF Comments at 11, 27-31

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27 Information about the Massachusetts GHG Inventory is available at https://www.mass.gov/lists/massdep-emissions-inventories (last visited November 29, 2023).

28 On October 14, 2022, individuals associated with the following organizations filed a joint set of comments as "interested persons": Greater Boston Physicians for Social Responsibility; Climate Reality Project Boston Metro Chapter; Gas Leaks Allies; Pipe Line Awareness Network for the Northeast; Fore River Residents Against the Compressor Station; Mothers Out Front; Ashland Sustainability Committee; Sierra Club; Acadia Center; Gas Transition Allies; Brookline GreenSpace Alliance; Emerald Necklace Conservancy; Elders Climate Action Massachusetts; and No Pipeline Westborough.

(May 6, 2022) ("CLF Initial Comments"); CLF Final Comments at 4 (October 14, 2022) ("CLF Final Comments"); Acadia Center Comments at 7). Finally, several commenters call for the use of a 20-year global warming potential ("GWP") value for methane, consistent with the most recent Intergovernmental Panel on Climate Change Fifth Assessment Report (see, e.g., CLF Initial Comments at 28; Acadia Center Initial Comments at 6-7).

Additionally, numerous commenters argue that the Pathways Report fails to vigorously pursue potential gas infrastructure cost savings, such as reduced GSEP spending and more optimistic networked geothermal cost assumptions (see, e.g., Attorney General Technical Comments at 21-23; CLF Initial Comments at 12, 51-53; Sierra Club Initial Comments at 20-21). Several commenters criticize the hybrid electrification pathway as being potentially skewed toward lower system-wide costs, noting that the Pathways Report's lower level of building shell retrofits and inclusion of residential hybrid fuel oil/ASHPs does not allow for an apples-to-apples comparison across pathways (see, e.g., Acadia Center Initial Comments at 19-21; Sierra Club Initial Comments at 5). Lastly, several commenters criticize the Pathways Report's consideration of health and air quality impacts, arguing that combining indoor and outdoor air quality into a single metric masks the risk of maintaining gas appliances in homes to the health of children, the elderly, environmental justice populations, and people with underlying health conditions (see, e.g., Greater Boston Physicians for Social Responsibility Comments at 7-9 (May 2, 2022); Massachusetts Medical Society Comments at 2-3 (May 3, 2022)).

C. LDCs Response to Stakeholder Comments

The LDCs reject the notion that the Pathways Report picks a preferred pathway, arguing that other pathways compare favorably to the hybrid electrification pathway, and that differences in the application of building shells and discount rates do not impact the Pathways Report's conclusions (LDC Joint Comments at 9, 40, 45-47). The LDCs contend the finding that decarbonization pathways that "strategically use the state's gas infrastructure alongside and in support of electrification are likely to carry lower levels of challenge" is not unique to this study, and that similar findings have been identified in both the U.S. and abroad (LDC Joint Comments at 9, 42-45). The LDCs maintain that the Pathways Report is a product of a significant amount of discussion and feedback from stakeholders, and that it is imperative for the Department and key stakeholders to approve the Net Zero Enablement Plans and Model Tariff (LDC Joint Comments at 13, 96).

The LDCs argue that the Consultants' recommendations draw from common strategies identified across all pathways and that suggestions that the benefits of hybrid electrification can be captured by balancing all-electric and conventional gas heat demands are at odds with a targeted electrification strategy that substantially reduces gas infrastructure investment (LDC Joint Comments at 9, 47-49). The LDCs maintain that the Pathways Report considers the potential for substantial avoided reinvestment in gas infrastructure, including reductions in GSEP spending and detailed consideration of networked geothermal potential (LDC Joint Comments at 8, 32-37). The LDCs assert that the alternative gas infrastructure cost comparisons provided by stakeholders are not comparable to those in the Pathways Report (LDC Joint Comments at 8, 37-38).

With respect to the availability and pricing of renewable fuels, the LDCs insist that the Pathways Report includes both optimistic and conservative ranges that are heavily derated to assess potential availability to Massachusetts and are based on the best available literature (LDC Joint Comments at 8, 19-26). The LDCs maintain that the Pathways Report's approach to pricing renewable fuels is consistent with similar industry studies in the Northeast, including the 2050 Roadmap (LDC Joint Comments at 8, 26-29). Additionally, the LDCs state that the Pathways Report's approach to emissions accounting is consistent with the Massachusetts GHG Inventory, 2050 Roadmap, and international reporting standards, and that the use of a 20-year GWP value for methane would require a reevaluation of the Commonwealth's 1990 emissions baseline (LDC Joint Comments at 9, 30, 49-53). Lastly, the LDCs argue that the Pathways Report's modeling of leakage rates is consistent with the official accounting framework used in the Massachusetts GHG Inventory and 2050 Roadmap, and that the Pathways Report sufficiently addresses qualitative health and air quality impacts (LDC Joint Comments at 9-10, 53-59).

D. Analysis and Conclusions

Consistent with the directives of the Department, the LDCs retained the Consultants to perform a detailed study for each LDC analyzing: (1) the feasibility of each decarbonization pathway identified by the Roadmaps; and (2) any pathways not examined in the Roadmaps, among other requirements. D.P.U. 20-80, at 3-5. The Department required the Consultants to combine the individual analyses into a single, collective report presenting: (1) a quantification of the costs and actual economy-wide GHG emissions reductions involved in transitioning the natural gas system; and (2) a discussion of qualitative factors such as impacts on public safety, reliability, economic development, equity, emissions reductions, and timing, for each identified pathway. D.P.U. 20-80, at 5-6.

To fulfill these directives, the LDCs submitted the Pathways Report, which identifies and discusses eight decarbonization pathways designed to allow for the comparison of the relative costs, risks, and feasibility of different futures (Pathways Report at 11, 34). The Department commends the LDCs and their Consultants for their comprehensive effort in estimating the costs and economy-wide GHG emissions reductions[29] involved in transitioning the natural gas system. The Department fully recognizes the difficulty in assessing these multidimensional challenges and expresses its appreciation for the comprehensive Pathways Report.

DOER notes significant alignment between the Pathways Report and the 2050 Roadmap, stating that the two documents demonstrate several common assumptions and outcomes (DOER Initial Comments at 6-8). However, commenters predominantly disagree over the Pathways Report's finding that strategically using the state's gas infrastructure

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[29] For each pathway involving electrification strategies, the Consultants were directed to provide a transparent depiction of key assumptions used in the analysis and a calculation of GHG emissions reductions, inclusive of GHG emissions from generation source. D.P.U. 20-80, at 5. The Department finds that the Pathways Report appropriately addressed this request (Pathways Report at 48; App. 1, at 21-28).

alongside and in support of electrification is likely to carry lower levels of challenge, most typified by the hybrid electrification pathway (see, e.g., Attorney General Final Comments at 6-19; DOER Initial Comments at 8-10; LDC Joint Comments at 40-48). Any further attempt to quantify alternative fuels, electrification technologies, and their associated GHG emissions reductions in a generic sense, is beyond the scope of the current investigation. The Department makes no findings related to a preferred pathway or technology here, as such considerations need to be made in the context of the distinct service territories of each LDC.[30] The Commonwealth's dominant building decarbonization strategy, however, is electrification as noted in the 2025/2030 CECP.[31] Our aim is to create and promote a regulatory framework that is flexible, protects consumers, promotes equity, and provides for fair consideration of the current and future technologies and commercial applications required to meet the Commonwealth's clean energy mandates and comply with the 2025/2030 CECP.

In doing so, the Department acknowledges that there is potential for further refinement to capture more fully the intricacies and granularity needed to achieve the Commonwealth's 2050 climate targets. Ultimately, the transition toward the Commonwealth's net zero targets will be one that is driven by the willingness and ability of residential, commercial, and industrial customers to support the Commonwealth's

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30 As noted above in Section IV, the Department must review LDC-specific plans in adjudicatory proceedings before approving any individual plan. St. 2022, c. 179, § 77.

31 2025/2030 CECP at 27, available at https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download (last visited November 29, 2023).

environmental goals and climate targets through investments in their homes, businesses, and transportation infrastructure. The Department seeks to expeditiously attain the GHG emissions reductions necessary to achieve these targets and will begin by more thoroughly addressing the six regulatory design recommendations below. Indeed, as we discuss in more detail in the next section, we recognize that new regulatory support strategies will be needed to minimize customer cost impacts regardless of which pathway, or combination of pathways, is pursued. After due consideration of the record, we find that the Pathways Report satisfies the Department's directives in opening this investigation in D.P.U. 20-80.

VI. REGULATORY DESIGN RECOMMENDATIONS

A. Introduction

The Consultants identify six regulatory design recommendations: (1) support customer adoption of and conversion to electrified/decarbonized heating technologies; (2) blend renewable gas supply into gas-resource portfolios; (3) pilot and deploy innovative electrification and decarbonized technologies; (4) manage gas embedded infrastructure investments and cost recovery; (5) evaluate and enable customer affordability; and (6) develop LDC transition plans and chart future progress. The Department here analyzes the merits of the various regulatory pathways proposed by the Consultants, and also uses this framework as a vehicle for identifying areas where we intend to pursue future investigation.

B. Support Customer Adoption of and Conversion to Electrified/Decarbonized Heating Technologies

1. Introduction and Summary

To meet the Commonwealth's climate targets, the decarbonization pathways will require significant levels of customer adoption of electrification and decarbonization heating technologies (Regulatory Designs Report at 19). The Regulatory Designs Report explains that certain pathways, such as high electrification, will require swift and early action to increase customer utilization (Regulatory Designs Report at 19). The Consultants recommend the following regulatory approaches to support customer use of electrification and decarbonization heating technologies: enhance and increase funding of energy efficiency programs; restructure electric and gas distribution rates; and revise customer service standards and procedures (Regulatory Designs Report at 20-24). These recommendations are discussed in detail below.

a. Energy Efficiency

To support customer adoption of electrification and decarbonization technologies identified in the pathways analysis, the Consultants recommend increasing energy efficiency program budgets, enhancing the programs to include new measures and strategies, and finding additional sources of funding (Regulatory Designs Report at 21). The Regulatory Designs Report emphasizes that the decarbonization pathways will require the deployment of new strategies and technologies (Regulatory Designs Report at 21). Since some decarbonization pathways target entire customer groups rather than individual customers to convert from natural gas to full electric service, energy efficiency programs will need to expand to support new incentive offerings and targeted electrification of entire customer blocks (Regulatory Designs Report at 21). The Consultants recommend evaluating the potential benefits of avoiding gas system infrastructure costs as part of targeted electrification or geothermal demonstration projects in the calculation of cost-effectiveness (Regulatory Designs Report at 21). The Regulatory Designs Report further explains that other enhancements may be necessary, including customer education and awareness, adoption of decarbonization strategies and technologies, and market transformation initiatives targeted at contractors, distributors, and manufacturers (Regulatory Designs Report at 21).

In addition, the Regulatory Designs Report states that the pathways will require larger energy efficiency budgets to support the enhanced initiatives discussed above (Regulatory Designs Report at 21). Since the current energy efficiency programs already are funded by ratepayers through the energy efficiency surcharge ("EES"),[32] the Consultants recommend evaluating additional funding sources to increase budgets and better align the benefits and cost responsibilities for certain programs between gas and electric companies (Regulatory Designs Report at 21-22). Specifically, the Consultants suggest offsetting some costs through a financial transfer from electric to gas utilities under a dual energy agreement (Regulatory Designs Report at 21-22).[33] A dual energy agreement involves a benefit-sharing mechanism

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32 The EES is included in the Local Distribution Adjustment Factor ("LDAF") of a customer's bill (Regulatory Designs Report at 21).

33 The Consultants cite a "dual energy" agreement between a Canadian electric company, Hydro-Quebec, and Energir, a gas company, in which gas customers in targeted market areas are converted to electricity to operate on electric heat during

that allows for a financial transfer from the electric company to the LDC as compensation for its role in electrification (Regulatory Designs Report at 22). The Consultants claim that a financial transfer reflects the economic and reliability benefits of maintaining the gas system to support electrification for hybrid heating customers (Regulatory Designs Report at 22).

b. Restructuring of Electric and Gas Rates

To support customer adoption of electrification and decarbonization technologies identified in the pathways analysis, the Consultants recommend examining electric and gas distribution rate policies to reflect the changing demand and infrastructure requirements of electrification (Regulatory Designs Report at 22-23). For example, the pathways analysis shows that increased use of electric heating shifts peak electric demand from summer to winter and, therefore, presents an opportunity to evaluate price signals associated with electric rates to reflect changing demand (Regulatory Designs Report at 22).

For electric distribution rates, the Consultants recommend exploring: (1) the potential of time-variant rates to reflect the cost of serving electricity demands during peak periods; and (2) critical peak-pricing rates that reflect the cost of serving higher electricity demands under extreme weather conditions (Regulatory Designs Report at 22). The Consultants explain that critical peak-pricing rates could be used to reflect the substantially higher cost of electricity generation, transmission, and distribution to meet demand during extreme weather

non-winter peak periods while operating on gas heat during winter peak periods (Regulatory Designs Report at 22).

conditions, and provide customers with an incentive to reduce electricity use during those weather conditions (Regulatory Designs Report at 22).

For gas distribution rates, the Consultants observe that the adoption of hybrid heating systems may change gas demand characteristics because these customers would be using the system only during peak winter periods (Regulatory Designs Report at 23). Because of this change, the Consultants suggest creating a rate class for customers with hybrid heating systems (Regulatory Designs Report at 23). The Consultants state that a hybrid rate class would establish rates to better reflect the costs associated with providing gas service exclusively during peak winter periods (Regulatory Designs Report at 23).

In addition to creating another rate class, the Consultants recommend changing the revenue decoupling mechanism ("RDM") (Regulatory Designs Report at 23-34). The current gas RDM is designed on a per-customer basis, which allows the LDCs to retain the incremental revenues associated with serving new gas customers to offset the incremental costs associated with those customers until distribution rates are reset (Regulatory Designs Report at 23-24). The Consultants explain that this mechanism has worked well with the historical increase in gas customers; most of the decarbonization pathways, however, anticipate a decrease in the number of gas customers over time (Regulatory Designs Report at 24). The Consultants recommend transitioning away from a revenues-per-customer approach to a reconciliation of total revenues (Regulatory Designs Report at 24). Under this approach, the LDCs would reconcile actual revenues and Department-authorized or target revenues rather than revenues per customer, and that reconciliation would include revenue from new customers (Regulatory Designs Report at 24).

c. Customer Service Standards and Procedures

The Consultants explain that certain decarbonization pathways will require updated customer service standards and procedures to support adoption of electrification and decarbonization technologies identified in the pathways analysis (Regulatory Designs Report at 24). Geographically targeted electrification, for example, would require all customers within a specific geographic area or neighborhood to convert from gas to electric or another alternative (Regulatory Designs Report at 24). The Consultants caution that such strategies may raise concerns over customer choice, cost, the LDCs' obligation to serve, and customer service protections (Regulatory Designs Report at 24). The Consultants recommend comprehensive measures to address various issues, including enhancing customer communication and education processes, expanding customer options for gas and electric services, providing financial support for customers, and fostering stronger relationships with contractors (Regulatory Designs Report at 24-25). These recommendations are aimed at facilitating and promoting the widespread adoption of electrification and decarbonization technologies among customers (Regulatory Designs Report at 24-25).

2. Summary of Comments

a. Energy Efficiency

Commenters agreed with increasing incentives and exploring new energy efficiency strategies to better support customer adoption of electrification and decarbonization heating technologies (see, e.g., Acadia Center Initial Comments at 21-22; OPOWER Comments at 3 (May 6, 2022)). Other commenters argue that energy efficiency incentives for gas appliances should be phased out (Sierra Club Comments at 21; CLF Initial Comments at 9). The Attorney General notes that the Department-approved 2022-2024 Three-Year Energy Efficiency Plans ("2022-2024 Three-Year Plans") include significant investments to promote the adoption of heat pumps, while also observing that the most recent plans already come with significant budget and bill impacts for customers (Attorney General Initial Comments,[34] App. C at 7). The Attorney General and Acadia Center support enhanced energy efficiency investment but encourage the LDCs to explore other funding sources beyond the EES to minimize customer bill impacts (Attorney General Initial Comments, App. C at 7; Acadia Center Initial Comments at 22-23). In addition to funding, commenters say workforce development needs further support to facilitate customer adoption (Attorney General Initial Comments at 54; Acadia Center Initial Comments at 22; HEET Comments at 7 (May 6, 2022) ("HEET Comments")). The Attorney General states that the Department should engage regularly with workforce stakeholders, through working groups or other means, to better inform the transition of gas distribution services (Attorney General Initial Comments at 54).

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[34] Regulating Uncertainty: The Office of the Attorney General's Regulatory Recommendations to Guide the Commonwealth's Gas Transition to a Net Zero Future (May 6, 2022).

The LDCs maintain that the Pathways Report does not adopt one pathway, but recommends energy efficiency as a low-regret strategy (LDC Joint Comments at 40-41). The LDCs reiterate that energy efficiency measures may decrease the impacts of electrification on the electric system and reduce demands for natural gas (LDC Joint Comments at 40-41). According to the LDCs, additional investment in energy efficiency will play a critical role in meeting the needs of an electrified economy (LDC Joint Comments at 6).

b. Rate Restructuring

Many commenters agree with the Consultants' recommendation to investigate changes to gas distribution rates and revenue decoupling (see, e.g., Attorney General Initial Comments at 38-39; Acadia Center Initial Comments at 23; and DOER Final Comments at 2). The Attorney General argues that the Department should conclude its investigation in Investigation to Review and Revise the Standard of Review and the Filing Requirements for Gas Special Contracts Filed Pursuant to G.L. c. 164, § 94, D.P.U. 18-152, and limit gas special contracts to only unique and novel public interest circumstances (Attorney General Initial Comments at 41). According to the Attorney General, gas special contracts[35] should demonstrate net benefits to customers, and that the customer's use of natural gas is no more harmful in terms of GHG and air pollutant emissions than the customer's alternative energy resource(s) (Attorney General Initial Comments at 41-43). The Attorney General also

[35] Gas special contracts allow LDCs to provide firm transportation service to customers at individually negotiated, off-tariff distribution rates. D.P.U. 18-152, Vote and Order Opening Investigation at 1 (2018).

recommends that the Department not permit LDCs to recover costs for marketing related to promoting gas service because these costs are not aligned with the Commonwealth's decarbonization goals (Attorney General Initial Comments at 41). Furthermore, the Attorney General asserts that any modifications to the current cost recovery mechanisms should consider equity, affordability, and preservation of customer choice (Attorney General Final Comments at 4).

Commenter RMI[36] posits that a hybrid heating scenario requires that customers do three things: electrify with heat pumps, retain utility gas backup, and use that gas backup sparingly (RMI Comments at 3 (May 6, 2022) ("RMI Initial Comments")). As a result, RMI argues, crafting an effective rate design for hybrid heating customers will be challenging given that to reduce emissions and remain economically viable, a hybrid rate design must both (1) recover the costs of the gas system without encouraging customers to use gas as their primary heating fuel, and (2) avoid customer departure from the gas system (RMI Initial Comments at 3). RMI argues that as gas demand declines and non-fossil gas is substituted for fossil gas, rising gas rates will become inevitable and may lead to significant cost recovery and equity challenges under a hybrid heating rate design (RMI Initial Comments at 3).

The LDCs maintain that there is still interest in natural gas service despite the momentum toward full electrification (LDC Joint Comments at 10). The LDCs acknowledge

36 Formerly "Rocky Mountain Institute" (RMI Initial Comments at 1).

concerns over increasing costs but reaffirm that the Regulatory Designs Report proposes potential rate designs to align equitably the benefits[37] and cost of hybrid heating (LDC Joint Comments at 75). Specifically, the LDCs contend that rate designs, such as a new hybrid rate class and critical peak pricing, will help incentivize customers to adopt and remain on hybrid heating systems (LDC Joint Comments at 75). The LDCs explain that a combination of customer education, financial support, and supportive policy initiatives will be necessary to spur the level of conversion needed for electrification modeled in each pathway (LDC Joint Comments at 10).

Additionally, the LDCs state that the potential of financial transfers from electric to gas utilities would help reflect the economic and reliability benefits of maintaining the gas system to aid the electric system during peak weather events (LDC Joint Comments at 75). The Sierra Club, however, opposes the sharing of costs between electric and gas customers (Sierra Club Initial Comments at 19; Sierra Club Comments at 12-13 (October 14, 2022) ("Sierra Club Final Comments")). The Sierra Club argues that electric customers subsidizing the decarbonization of the gas sector would constitute an inappropriate cross-subsidization given that the electric sector already has "borne its share of decarbonization costs" (Sierra Club Initial Comments at 19; Sierra Club Final Comments at 12-13).

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37 The LDCs explain that hybrid electrification is beneficial because it allows customers to leverage their existing equipment as a backup heating system (LDC Joint Comments at 74).

The LDCs reaffirm that most of the decarbonization pathways will result in service to fewer gas customers over time (LDC Joint Comments at 90). The LDCs recommend revising the RDM from a per-customer basis reconciliation of actual and authorized revenues to a reconciliation of total revenues (LDC Joint Comments at 90, citing Regulatory Designs Report at 23-24). The LDCs agree that replacing the RDM per customer with a total revenues or revenue cap decoupling is better aligned with the Commonwealth's decarbonization goals (LDC Joint Comments at 90-91). The Attorney General likewise agrees with revising the RDM (Attorney General Initial Comments at 39).

c. Affordability and Customer Choice

Several commenters also expressed affordability concerns, particularly for low- and moderate-income ("LMI") customers. Many commenters called for the prioritization of LMI customers to ensure an equitable transition and protect them from bearing the increased energy burden associated with electrification (see, e.g., NCLC Comments at 32 (May 6, 2022) ("NCLC Initial Comments"); LEAN Comments at 2-3 (May 6, 2022) ("LEAN Initial Comments"); Sierra Club Final Comments at 12). Some commenters, such as Acadia Center, disagree with charging customers exit fees[38] to leave the gas system because it may hinder electrification affordability (see, e.g., Acadia Center Initial Comments at 24; RMI Initial Comments at 3). LEAN recommends increasing low-income discounts and offering an exemption from the bill impacts of accelerated deprecation for LMI customers (LEAN Initial

[38] An "exit fee" or "migration charge" which would be charged to customers leaving the natural gas system is defined and discussed further in Section VI.F.

Comments at 17). In sum, numerous commenters express concerns that the LDC transition plans may impose an unfair burden on LMI customers in the absence of regulatory intervention.

The Attorney General confirms that, absent regulatory reform, remaining gas customers will experience significant rate increases as other customers leave the system (Attorney General Initial Comments at 46). Many commenters agree that LMI customers are less likely to leave the gas system and, therefore, may be disproportionately impacted by higher energy bills (see, e.g., HEET Comments at 7; LEAN Initial Comments at 17). The Attorney General explains that LMI customers currently spend a higher percentage of their income on utility bills than any other income group (Attorney General Initial Comments at 48). The Attorney General recommends that the Department consider adopting a rate mechanism to protect LMI customers from high energy burdens and potential rate increases (Attorney General Initial Comments at 50). Specifically, the Attorney General states that there should be a cap on the amount an LMI customer is billed (Attorney General Initial Comments at 52). Other commenters agree that the LDCs should consider rate mechanisms to help protect LMI ratepayers from high energy burdens and potential rate increases (see, e.g., DOER Initial Comments at 15; LEAN Initial Comments at 18).

Regarding customer choice, many commenters support a full transition away from fossil fuels via electrification. A handful of commenters do not (see, e.g., Tufts Medicine Lowell General Hospital Comments at 1; Inovis Energy, Inc. Comments at 1-2 (July 13, 2022); Mass Coalition for Sustainable Energy Comments at 1 (October 6, 2022)). One commenter noted that full electrification should be contingent on adequate renewable energy production (Shell USA, Inc. Comments at 4). Other commenters support electrification alongside geothermal and other low-carbon heating options (see, e.g., CLF Initial Comments at 12; Martin Comment at 1 (May 6, 2022)). Commenters acknowledge the LDCs' obligation to serve current gas customers but suggest revising the obligation to serve standards (see, e.g., Pipeline Awareness Network for the Northeast, Inc. ("PLAN") Comments at 4 (May 6, 2022) ("PLAN Initial Comments"); CLF Initial Comments at 21). PLAN states that the obligation to serve criteria apply only to existing customers (PLAN Comments at 5 (October 14, 2022) ("PLAN Final Comments").

The LDCs reiterate that customer choice will drive the acceptance of electrification but maintain that there is public support for preserving the natural gas system (LDC Joint Comments at 93-94, citing Exh. DPU-Comm 2-13, Att.). The LDCs highlight the substantial upfront costs for electrification as a barrier to conversion (LDC Joint Comments at 95, citing Pathways Report, Figure 4, at 17). The LDCs state that the Net Zero Enablement Plans contain strategies to help educate customers around their energy options (LDC Joint Comments at 94). Furthermore, the LDCs assert that achieving the levels of electrification modeled in each pathway will hinge not only on customer education, but also on supportive policy initiatives and market transformation activities that help customers overcome the upfront cost barriers to electrification (LDC Joint Comments at 94-95). The LDCs view current and future pilot projects as an opportunity to test and evaluate different market transformation approaches, including various incentive strategies to facilitate customer implementation of electrification and decarbonization heating technologies (LDC Joint Comments at 96, citing Exh. DPU-Comm 5-6).

3. Analysis and Conclusions

a. Introduction

The Department recognizes that significant levels of customer acceptance of electrification and decarbonization technologies will be needed for the Commonwealth to achieve its climate targets. While LDCs already have begun to increase the level of customer implementation of energy efficiency and decarbonized technologies through their 2022-2024 Three-Year Plans, more will need to be done inside and outside of the energy efficiency rubric to prioritize electrification, equity, and workforce development (Regulatory Designs Report at 20). See also 2022-2024 Three-Year Energy Efficiency Plans, D.P.U. 21-120 through D.P.U. 21-129, at 42, 46-47, 51 (2022) ("2022-2024 Three-Year Plans Order"). The Consultants recommend enhancing energy efficiency programs and funding to incentivize customer participation; restructuring gas and electric distribution rates to reflect the changing demand and infrastructure requirements of electrification; and establishing new customer service standards and procedures to facilitate and promote the widespread use of electrification and decarbonization technologies among customers (Regulatory Designs Report at 20-21). Commenters offer a range of perspectives on the transition to cleaner energy sources, with a focus on mitigating the impact on customers, especially those with lower incomes, and the role of incentives, rate structures, and policy initiatives in shaping the energy landscape. We address these recommendations below.

b. Energy Efficiency

The Department recognizes the importance of programs with effective participant incentives to help facilitate increased electrification and use of decarbonization technologies. The LDCs have strategies to leverage their cost-effective energy efficiency plans and strategies to encourage electrification through heat pumps and other measures. 2022-2024 Three-Year Plans Order at 51-52. In addition, under the Green Communities Act,[39] three-year plans must achieve all cost-effective energy efficiency, pass the cost-effectiveness analysis using the total resource cost test,[40] direct 20 percent of budgets to low-income energy efficiency, minimize administrative costs, maximize competitive procurement, and be mindful of bill impacts on gas ratepayers. G.L. c. 25, § 21(b)(1). In addition, beginning with the 2025-2027 three-year energy efficiency plans, there shall be "no spending on incentives, programs or support for systems, equipment, workforce development or training as they relate to new fossil fuel equipment unless such spending is for low-income households, emergency facilities, hospitals, a backup thermal energy source for a heat pump, or hard to electrify uses, such as industrial processes." G.L. c. 25, § 21(b)(2)(xi). Further, the Department already must consider whether these plans are constructed to meet or exceed the GHG emissions reduction mandates set by the EEA Secretary pursuant to G.L. c. 21N,

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39 An Act Relative to Green Communities, Acts of 2008, chapter 69, section 11.

40 In determining cost-effectiveness, the calculation of benefits shall include the social value of GHG reductions, except in the cases of conversions from fossil fuel heating and cooling to fossil fuel heating and cooling. G.L. c. 25, § 21(b)(1).

§ 3B. Finally, the Department considers whether the proposed plans adequately prioritize safety, reliability, security, affordability, and equity. 2022-2024 Three-Year Plans Order at 84.

The 2022-2024 Three-Year Plans have made significant steps in promoting both energy efficiency and electrification through customer incentives and performance incentives. See 2022 Energy Efficiency Annual Reports, D.P.U. 23-60, Berkshire Gas Company, App. 1, at 2-3 (June 1, 2023). The Department expects the LDCs to continue expanding the scope of ambition in their three-year plans to promote reductions in overall energy usage that result in cost-effective programs, while balancing increased electrification to meet GHG emissions reduction targets.

At the same time, the Department remains concerned about customer bill increases associated with enhancing the Commonwealth's energy efficiency programs. The Regulatory Designs Report recommends minimizing the potential bill impacts of these program enhancements by using other funding sources, such as government funding, gas system exit fees, and financial transfers from electric to gas utilities (Regulatory Designs Report at 44 n.57; Exh. DPU-Comm 3-3). Since 2010, the Department has required gas three-year plans to include all other sources of funding that program administrators have pursued to help fund the energy efficiency programs.[41] Investigation by the Department of Public Utilities on

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41 In approving an energy efficiency funding mechanism for the electric program administrators, the Department must consider the availability of other private or public funds. G.L. c. 25, § 19(a)(3)(ii).

its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 20-150-A, App. A, § 3.2.2.1 (2021), ("Guidelines"). The Department reminds program administrators that this requirement to pursue non-ratepayer sources of funding is more important now than ever, especially for residential and small-business customers who disproportionately bear the burden of higher energy efficiency surcharges as compared to other rate classes. The Department, however, declines to implement exit fees or financial transfers as viable outside funding sources to offset the cost of expanding energy efficiency budgets. As discussed in Section VI.F below, the Department is concerned that charging an additional fee to exit the gas system may disincentivize customers from fully electrifying. At the same time, in the absence of a gas exit fee, residential and small business customers who are not able to leave the system may bear even higher energy bills. The Department is open to reviewing any alternative funding sources so long as they help facilitate a safe, reliable, and equitable transition for all ratepayers.

Lastly, in response to the Attorney General's recommendation to engage with workforce stakeholders, the Department recognizes that the utility and energy contractor workforce will play an integral role in customer acceptance of electrification and decarbonization technologies. Workforce development is essential to safe and reliable gas operations and will be at the forefront of the industry transition. As required by G.L. c. 25, § 19(d), the annual workforce development program budget of $12 million is explicitly allocated from the 2022-2024 Three-Year Plans to MassCEC to grow and diversify a clean energy equity workforce and market development program in the Commonwealth.[42] 2022-2024 Three-Year Plans Order at 42. The Department accepts that significant efforts will be required to develop strategies to train and ensure family-sustaining wages for a workforce to support the energy transition. It is critical to train current gas system workers for employment opportunities in the clean energy sector. It is also important that jobs are available in the clean energy sector to support workers who are women, people of color, Indigenous Peoples, veterans, people living with disabilities, immigrants, and people who were formerly incarcerated. A comprehensive workforce strategy requires solutions that ensure the well-being of workers and communities, create jobs, and contribute to a thriving and sustainable economy. This strategy should be viewed as part of a just transition framework.

The Department, therefore, strongly encourages the LDCs to engage with other stakeholders, including labor unions, MassCEC, and existing workforce development programs, to establish a just transition framework for gas industry workers and people who have largely been left out of the clean energy workforce to start training for jobs that support

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42 General Laws c. 25, § 19(d), added by the 2021 Climate Act, requires the Department to annually collect and transfer not less than $12 million to MassCEC for the clean energy equity workforce and market development program established pursuant to G.L. c. 23J, § 13. MassCEC states that this funding will be used for assisting environmental justice populations to plan and develop career training programs for employment in high demand clean energy occupations, and to provide support for expansion and creation of minority- and women-owned business enterprises in business categories critical to state climate targets. Massachusetts Clean Energy Center Request for Fiscal Year 2023 Funding Pursuant to G.L. c. 25, § 19(d), D.P.U. 22-75, Letter Order at 1 (June 27, 2022).

electrification and decarbonization. The LDCs shall provide an update on this just transition framework in their future Climate Compliance Plans, which the Department details in Section VI.G below.

c. Rate Restructuring

The LDCs propose evaluating alternative rate designs to better reflect the changing demand and infrastructure requirements of electrification and agree with the recommendation to change the RDM structure (Regulatory Designs Report at 22-23). The Department supports the alignment of LDC rate designs with climate objectives and GHG reduction compliance pathways.[43] In particular, the Department agrees with the recommendation to replace the current per-customer RDM with a total revenues or revenue cap decoupling mechanism. The Department finds that a revenue cap approach, which subsequently disincentivizes LDCs to expand their gas customer base, better aligns with the policies of the Commonwealth expressed in current climate laws. The Department directs each of the LDCs to propose an RDM that implements this approach in its next rate case. The Department also encourages the LDCs to evaluate and propose alternative rate resigns and other cost recovery mechanisms that are consistent with the direction provided in this Order.

The Department acknowledges that the LDCs and Consultants identify hybrid heating systems as a low-regret strategy toward decarbonization and takes notice of the significant

43 When considering new rate designs, the Department is required to take into consideration the reduction of GHG emissions pursuant to the 2022 Clean Energy Act. G.L. c 164, § 141.

uptick in utilization of heat pumps under the current three-year plans.[44] As we discuss in Section VI.D, however, the Department is not persuaded that pursuit of a broad hybrid heating strategy that would necessitate maintenance of the natural gas system to support backup heating systems is a viable path forward. Given improvements in technology, the Department expects that cold-climate heat pumps generally will eliminate the need for backup heating systems. During this transition period, however, the Department accepts that customers may elect to retain their previous backup heating systems, such as gas-fired boilers, to support heat pumps, as discussed further in Section VI.D. The LDCs shall continue to track customer heat pump installations. Further, the LDCs must work with their energy contractors and vendors to provide sufficient information to customers about the capabilities of heat pumps so they may reach a more informed conclusion about the true need for backup heating systems. If the LDCs propose a new rate design for hybrid heating customers, then they must strike a balance between recovering the costs of the gas system without encouraging customers to use gas as their primary heating fuel, thereby enabling

44 To date, three gas program administrators have filed mid-term modification requests in 2023 for additional funding partially due to a higher-than-expected demand for heat pumps (see Berkshire Gas Company, D.P.U. 23-93, Pre-Filed Testimony of Hammad Chaudhry and Jillian Winterkorn at 3-4; Liberty Utilities, D.P.U. 23-91, Pre-Filed Testimony of Kimberly Gragoo, Stephanie Terach, and Autumn R. Snyder at 6-7; Fitchburg Gas and Electric Light Company, D.P.U. 23-70, Pre-Filed Testimony of Cindy L. Carroll and Mary A. Downes at 6).

GHG emissions reductions while maintaining low operating costs to retain customers.[45] The Department will consider all other rate restructuring proposals on a case-by-case basis.

With respect to special gas contracts, we acknowledge the Attorney General's suggestion that the Department conclude its investigation in D.P.U. 18-152 and limit gas special contracts to only unique and novel public interest circumstances (Attorney General Initial Comments at 41). The Department agrees that the requirements for gas special contracts should be improved and refined, and that the ongoing investigation in D.P.U. 18-152 is the proper vehicle for the pursuit of any such changes. Given that D.P.U. 18-152 remains an open proceeding, we decline to address the specifics or potential outcomes here other than to acknowledge that a re-examination of gas special contracts is part of the portfolio of actions we are taking to facilitate the necessary transition of the natural gas industry.

Finally, we agree with the Attorney General that LDCs should not be permitted to include in rates any costs associated with marketing geared toward the promotion or expansion of gas service. As noted by the Attorney General, these costs are not aligned with the Commonwealth's decarbonization targets and any continued funding of such advertising or marketing by ratepayers is the type of "business as usual" operations of LDCs that must

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[45] In the context of hybrid heating and a hybrid heating rate design, the importance of customer retention via low operating costs is so that increasing costs do not incent those customers most able to afford full electrification to pursue that option (or delivered fuels) while leaving lower-income customers on a rate that potentially would rapidly increase to account for fewer customers supporting the system (RMI Initial Comments at 2-3). This is inconsistent with an equitable transition.

cease. Moreover, this prohibition on ratepayer funding of gas marketing extends not only to initiatives undertaken directly by LDCs, but includes indirect efforts to promote either natural gas expansion or policies geared toward promoting natural gas expansion. If and to the extent LDCs wish to continue participating in such efforts, the associated costs will be borne entirely by shareholders.

d. Affordability and Customer Choice

The pace of customer transition to alternatives to natural gas is a significant uncertainty facing gas industry sales and revenue projections. Many commenters argued for the prioritization of LMI customers to ensure an equitable transition (see, e.g., NCLC Initial Comments at 32; LEAN Final Comments at 2-3; Sierra Club Final Comments at 12). The Attorney General contends that that the Department should consider adopting a rate mechanism to protect LMI customers from high energy burdens and potential rate increases (Attorney General Initial Comments at 50).

The Department agrees that the pace of customer transition to gas alternatives will depend on a suite of available incentives, education, legislative change, and market transformation activities. Ensuring an affordable and equitable transition will be among the most potentially challenging aspects of this undertaking. A mass exodus of gas customers has the potential to shock rates to the detriment of remaining ratepayers and reduce utility revenues, jeopardizing the LDCs' continued provision of safe and reliable service to remaining customers, as well as posing a potential general safety risk to the public at large. Conversely, less competition from alternatives may result in a slower pace of transition and delay the necessary achievement of the climate targets. The Department and LDCs will need to take steps to minimize the impacts of long-term competitive losses. The Department will address the practicality of such strategies through the remainder of this Order, including modification of line extension policies that assume long-term sales revenue, shifting revenue from traditional rate base to performance-based mechanisms that incent reduced emissions, and rate structures that protect LMI customers.

As to preserving customer choice, it is not clear that the Department has the statutory authority to prohibit the addition of new gas customers. It is the Department's long-standing policy, however, that an LDC need not serve new customers in circumstances in which the addition of new customers would raise the cost of gas service for existing firm ratepayers. Boston Gas Company, D.P.U. 88-67 (Phase I) at 282-284 (1988). An LDC must therefore first ensure that the incremental costs to expand its distribution network do not exceed the incremental revenues from such expansion to include the cost of expanding its distribution network in rates. Bay State Gas Company, D.P.U. 12-25, at 379 (2012); Boston Gas Company, D.T.E. 03-40, at 48 (2003). LDCs determine whether a main or service extension is economically feasible using a model to compare the estimated cost of the project to the estimated revenues over the expected useful life of the plant investment to ensure the internal rate of return exceeds the rate of return allowed in the Company's most recent base distribution rate case. See, e.g., NSTAR Gas Company, D.P.U. 19-120, at 456-457 (2020) (reviewing the company's main extension policy in the course of analyzing a surcharge proposal pursuant to St. 2014, c. 149, § 3); Boston Gas Company, D.P.U. 89-180, at 16-17

(1990). When an investment needed to serve a new customer does not pass the internal rate of return test, the gas company may require the customer to pay a contribution in aid of construction ("CIAC") to make up the deficit. D.P.U. 19-120, at 456-457.[46] It thus appears that there is an opportunity to revise the process of making this cost determination, reviewing tariff provisions, and current LDC practices to disincentivize further customer expansion while still preserving customer choice to the extent necessary. These changes are further discussed in Section VI.E below.

C. Blend Renewable Gas Supply Into Gas-Resource Portfolios

1. Introduction and Summary

The Regulatory Designs Report recommends that the LDCs develop a procurement strategy to add renewable gas options to their resource portfolios (Regulatory Designs Report at 25). As used by the Consultants, "renewable gas supply" is an umbrella term that refers to renewably produced alternatives to natural gas that includes biomethane produced through anaerobic digestion or gasification, renewable hydrogen, and SNG produced from renewable hydrogen and a climate-neutral source of carbon (Pathways Report at 9; Regulatory Designs Report at 6, 25). The Consultants note that blending limited amounts of renewable gases into the pipeline could result in a reduction of GHG emissions without a corresponding substantial increase in overall gas costs (Regulatory Designs Report at 25). The Consultants recommend

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46 Property that has been contributed to a utility is not included in rate base. D.P.U. 12-25, at 380 n.220, citing Milford Water Company, D.P.U. 771, at 21 (1982); Oxford Water Company, D.P.U. 18595, at 18 (1976); Commonwealth Gas Company, D.P.U. 18545, at 2 (1976).

that the LDCs investigate the deliverability of biomethane, hydrogen, and synthetic gases from a broader range of resources and regions to clarify further their role in supporting the state's decarbonization goals and ensure that these fuels in fact can meet the requirements of the pathways (Regulatory Designs Report at 25). Finally, the Regulatory Designs Report recognizes that renewable gas does not meet the Department's least-cost standard (Regulatory Designs Report at 25). The Consultants make three specific recommendations intended to enable LDCs to incorporate renewable gas supply into the system: (1) update the forecast and supply planning standards to add renewable gas; (2) provide customers with an option to purchase renewable gas from the LDC; and (3) provide customers with an option to purchase renewable gas from third-party suppliers (Regulatory Designs Report at 25-26).

According to the Regulatory Designs Report, the Department should update its forecast and supply planning[47] standards to require a minimum level of renewable gas and

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47 Pursuant to G.L. c. 164, § 69*I*, every gas company shall file for the Department's approval a long-range forecast with respect to the gas requirements of its market area for the ensuing five-year period, consisting of the gas sendout necessary to serve projected firm customers and the available supplies necessary to meet the projected demand. Further, the Department reviews a gas company's five-year supply plan to determine whether the plan is adequate to meet projected normal-year, design-year, design-day, and cold-snap firm sendout requirements. Fitchburg Gas and Electric Light Company, D.P.U. 21-10, at 3 (2022).

Under its current standards, the Department determines if a company's projection method is reasonable based on whether the method is: (a) reviewable, that is, contains enough information to allow a full understanding of the forecast method; (b) appropriate, that is, technically suitable to the size and nature of the particular gas company; and (c) reliable, that is, provides a measure of confidence that the gas company's assumptions, judgments, and data will forecast what is most likely to incorporate the cost of carbon in the LDCs' supply plan economic analysis (Regulatory Designs Report at 25). The Consultants posit that either a Renewable Heating Fuel Standard ("RHFS") or a Renewable Portfolio Standard ("RPS") could establish a minimum level of RNG, similar to the electric industry (Regulatory Designs Report at 25). The Consultants suggest that either the Legislature or the Department via a generic proceeding could authorize an RHFS or RPS, and that the minimum level of renewable gas could be set low initially to address concerns with availability and cost, with subsequent increases subject to these considerations (Regulatory Designs Report at 25-26). A second approach to updating the forecast and supply standards discussed by the Consultants is the addition of a cost of carbon to the supply planning economic analysis, which would provide an economic advantage to low-carbon supplies (Regulatory Designs Report at 26). As in the context of the RHFS and RPS option, the Consultants assert the cost of carbon initially could be set low to address supply availability, cost, or customer affordability considerations and then increased gradually subject to these considerations (Regulatory Designs Report at 26).

The Consultants' second recommendation for incorporating renewable gas into the system is to provide LDC customers who want to reduce their carbon emissions the option to purchase renewable gas directly from the LDC (Regulatory Designs Report at 26). In this scenario, the Department would approve a tariff through either an LDC-specific rate-setting

occur. D.P.U. 21-10, at 3, citing Bay State Gas Company, D.T.E. 02-75, at 2 (2004); The Berkshire Gas Company, D.T.E. 02-17, at 2 (2003).

proceeding or through a generic proceeding applicable to all LDCs (Regulatory Designs Report at 26).

With respect to the third recommendation to facilitate use of renewable gas, the Regulatory Designs Report recommends that the Department provide customers with an option to purchase renewable gas from third-party suppliers via each LDC's delivery service (Regulatory Designs Report at 26). The Consultants posit that this approach may be appealing to customers, especially large commercial and industrial customers, seeking to purchase directly from a third-party supplier. The Regulatory Designs Report recognizes that a special tariff may be required to address interconnection requirements (Regulatory Designs Report at 26).

Finally, and applicable to all three design approaches discussed above, the Consultants recommend a procurement strategy that includes customer education, marketing, and incentives that promote the integration of renewable gas into the gas system. This would facilitate customer understanding of the benefits and cost implications of renewable gas and their options to incorporate it into their fuel mix (Regulatory Designs Report at 27).

2. Summary of Comments

Generally, commenters agree in their objections to the recommendations in the Regulatory Designs Report regarding renewable gas.[48] Numerous commenters raised issues

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48 While the Pathways Report refers to "renewable gas," commenters also refer to renewable natural gas or "RNG," which along with SNG and hydrogen, may also be referred to as "decarbonized gas" (Attorney General Initial Comments at 11-12). The

and concerns related to emissions, system upgrades and related costs, and the availability of alternatives.

The Attorney General argues that the Pathways Report overstates the availability of RNG and understates RNG's costs (Attorney General Technical Comments at 8-16; Attorney General Final Comments at 20). The Attorney General asserts that there is no credible basis to assume that RNG can be made available in Massachusetts at the volumes needed to support the gas use in 2050 assumed under the hybrid electrification scenario, and further that the Consultants significantly understate the costs of obtaining RNG (Attorney General Technical Comments at 8-16). The Attorney General argues that, in developing their price projections for RNG, the Consultants developed a weighted average price for RNG instead of pricing it at the incremental price of the marginal unit of supply (Attorney General Final Comments at 21). Moreover, the Attorney General asserts that the continued use of biomethane is inconsistent with the Commonwealth's policy as set forth in EEA's 2025/2030 CECP (Attorney General Final Comments at 21-22). The Attorney General also questions the Consultants' assumption that RNG is carbon neutral (Attorney General Technical Comments at 16-19). Further, the Attorney General notes that RNG and hydrogen, although emerging, are unproven and uncertain technologies that carry significant investment risks (Attorney General Initial Comments at 32). The Attorney General therefore recommends that

Attorney General and others assert, however, that the term "decarbonized gas" is a misnomer (Attorney General Initial Comments at 11 n.48).

the Department ensure that investments in unproven or uncertain technologies are borne entirely by utility shareholders (Attorney General Initial Comments at 32).

DOER suggests that the Department consider R&D proposals intended to increase the supply of RNG and hydrogen (DOER Initial Comments at 11). DOER also proposes that the Department disallow long-term contracts that would lock customers into high-risk and high-cost resources for long periods (DOER Initial Comments at 16). Finally, DOER proposes that the Department should require the LDCs to complete R&D projects using RNG to demonstrate emissions reductions consistent with the GWSA methodology before it approves any long-term contracts for renewable gas or hydrogen (DOER Final Comments at 15).

Acadia Center argues that the proposals involving RNG: (1) fail to account for out-of-state emissions occurring during the productions and transmission of the fuels; (2) dramatically underestimate the level of methane leaks from the natural gas systems in Massachusetts; (3) assume that biofuels are GHG-neutral; and (4) underestimate the availability and price of RNG and hydrogen (Acadia Center Initial Comments at 5-15).

Similar to Acadia Center, Sierra Club asserts that the Consultants underestimate the levels of GHG emissions from RNG and SNG, and also underestimate the availability of and clearing prices for renewable gas (Sierra Club Initial Comments at 8-11). In addition, Sierra Club argues that hydrogen is an inefficient and unfeasible strategy to decarbonize buildings (Sierra Club Initial Comments at 14-17). Finally, Sierra Club argues that even if the LDCs' treatment of biofuels as zero-GHG emitting is consistent with both the Commonwealth's current GHG accounting methodologies and its 2050 Roadmap, that is an inadequate basis for assessing the relative merits of biofuel investments as part of a decarbonization strategy (Sierra Club Final Comments at 6-8).

CLF argues that there is insufficient evidence to support the claim that biomethane is a zero-emissions fuel over the course of its lifecycle (CLF Final Comments at 4). Regarding hydrogen, CLF argues that it is highly volatile and will have to be limited to applications and sectors that cannot be electrified (CLF Final Comments at 4). CLF contends that LDCs would have to prove that biomethane is a zero-carbon fuel before forecast and supply plan standards should be allowed to include RNG, or before customers should be given the option to purchase RNG from LDCs or from third parties (CLF Initial Comments at 14). CLF maintains that the Consultants' technical analyses around the impact of biomethane were based on assumptions not grounded in science or reality (CLF Initial Comments at 14). In addition, EDF contends that there is a good understanding of the climate and safety impacts of renewable fuels, noting that hydrogen emissions have global warming potential (EDF Comments at 6–8 (October 13, 2022) ("EDF Final Comments")).

Dozens of individual and group commenters raised concerns similar to those recited above, specifically arguing against the mandated use of RNG and/or hydrogen based on issues related to supply availability, GHG emissions, safety, and cost (see, e.g., Interested Persons Comments at 2-3; Elders Climate Action Massachusetts Comments at 1-3 (May 6, 2022); Callaway Comments at 1 (May 4, 2022); Fortuin Comments at 1-2 (May 6, 2022); Phillips Comments at 1 (May 6, 2022)).

The LDCs argue that RNG and other alternative fuel sources are a necessary component of any decarbonization future and that the path to net zero does not need to be a binary decision between fuel sources and a fully electrified system (LDC Joint Comments at 60). The LDCs contend that adding RNG to the supply portfolio will produce environmental benefits, contributing to achievement of the Commonwealth's objectives, and will improve supply availability and diversity, both critical gas supply planning considerations (LDC Joint Comments at 60-61). Further, the LDCs point out that to fully electrify, a significant overbuild of renewables will be required to ensure peak demand can be met by the electric network (LDC Joint Comments at 62). The LDCs assert RNG can complement electrification by supporting the intermittent nature of renewable generation resources like solar and wind (LDC Joint Comments at 62).

Regarding the various comments expressing skepticism that RNG can be scaled to the level needed and purchased at a reasonable cost, the LDCs state that they expect the availability of RNG to continue to grow as technologies to develop RNG continue to advance (LDC Joint Comments at 63). Finally, regarding the criticism that the Consultants treat renewable gases as carbon neutral, the LDCs assert that this approach is consistent with both the official GHG accounting methodology of the Commonwealth and the 2050 Roadmap (LDC Joint Comments at 30).

3. Analysis and Conclusions

The Consultants recommend that the LDCs develop a procurement strategy to add RNG supply to the resource portfolio. The Department has been presented with three specific means of enabling the LDCs to incorporate RNG supply into their gas system: (1) update the forecast and supply planning standards to incorporate RNG through either a RHFS/RPS or the addition of a cost of carbon; (2) provide customers with an option to purchase RNG from the LDC; and (3) provide customers with an option to purchase RNG from third-party suppliers (Regulatory Designs Report at 25-26).

Most commenters did not address directly the suggestion that the Department update the forecast and supply planning standards to incorporate RNG. Numerous comments did note, however, that RNG does not provide measurable benefits in terms of costs and emissions reductions.

Our policy regarding the LDCs' procurement of gas resources is well established. The Department first articulated its standard for commodity and capacity acquisitions in Commonwealth Gas Company, D.P.U. 94-174-A (1996), where the Department determined that to demonstrate that the proposed acquisition of a resource that provides commodity and/or incremental resources is consistent with the public interest, an LDC must show that the acquisition is (1) consistent with the company's portfolio objectives; and (2) compares favorably to the range of alternative options reasonably available to the company at the time of the acquisition or contract renegotiation. D.P.U. 94-174-A at 27. In Liberty Utilities (New England Natural Gas Company) Corp., D.P.U. 22-32-C at 36 (2022), the Department also noted that we must consider whether the proposed acquisition is consistent with the GWSA and any applicable emissions limit or sublimit set by the Secretary of EEA. G.L. c. 25, § 1A. At this time, as we discuss below, we have been presented with no evidence convincing us to alter this gas procurement policy. On the contrary, we share the concerns raised by various stakeholders regarding costs, availability, and the treatment of renewable fuels as carbon neutral.

As the LDCs acknowledge, RNG currently does not meet the Department's least-cost supply planning standards given the higher cost of RNG relative to pipeline gas. Given this, the inclusion of RNG supplies in an LDC's resource portfolio would violate our goal of providing gas service at the lowest possible cost. Indeed, the higher cost of RNG raises customer affordability concerns as LDC rates will be higher than they otherwise would be if pipeline gas continued to be used.

We recognize that RNG and the use of hydrogen as a fuel are emerging technologies that have not yet been proven to lead to a net reduction in GHG emissions. The Consultants assume that RNG's emissions are carbon neutral under the Commonwealth's current GHG accounting framework (Regulatory Designs Report at 8 n.7). They acknowledge that if the GHG emissions accounting conventions change, however, the potential of RNG as a carbon-neutral fuel diminishes and its value in terms of decarbonization would be overstated (Pathways Report at 18 n.12). In our view, more studies are required in this area to support the claim that RNG is a zero-emissions fuel. For example, a full life-cycle analysis that considers all of the emissions profiles and captures emissions gains and losses throughout the entire production process may be necessary to determine the total carbon intensity of RNG.

Regarding the availability of RNG, we are not convinced that sufficient RNG stocks will be available to ensure the alleged potential environmental benefits. Record evidence shows that there is significant uncertainty regarding the availability of RNG (Pathways Report, App. 1, at 16). Indeed, the Consultants note that biomass resource availability in New England is relatively low compared to other regions in the United States. New England has an estimated 0.63 dry tons of feedstocks available per person per year, whereas the average availability of feedstocks for the U.S. as a whole, is 2.47 dry tons per person per year (Pathways Report, App. 1, at 15). According to the Coalition for Renewable Natural Gas, of the 300 RNG facilities in the U.S., only eight are located in New England.[49] In the long run, RNG supply shortages may lead to higher costs. For these reasons, we have no basis in the existing record for altering our existing gas procurement policy as established in D.P.U. 94-174-A to allow for the acquisition of RNG and or the imposition of a RHFS or cost of carbon in the LDCs' supply plan economic analyses. We recognize, however, that the technology is evolving and the process to produce RNG may possibly lead to measurable benefits in the future, particularly for hard-to-electrify industrial processes. We encourage LDCs to investigate all options that will lead to a reduction in their GHG footprint, including lifecycle emissions associated with system operations, and we will review any proposals that are consistent with existing standards as well as with the Commonwealth's GWSA and the 2021 Climate Act.

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49 See https://www.rngcoalition.com/?gad=1&gclid=Cj0KCQjwpc-oBhCGARIsAH6ote-K_4nSXK5AbiPbzM5IqeZD-AfyAg7WWyM5sfivAv_6_Q3Uvs9i4sYaAgadEALw_wcB (last visited November 29, 2023).

As the Commonwealth strives to achieve its 2050 climate targets, we envision that the long-term use of the natural gas distribution system generally will be limited to strategic circumstances where electrification is not feasible for all natural gas applications. For example, we recognize that some C&I customers require natural gas for process heat applications for which there are currently no electric-driven alternatives. It would therefore be necessary to make RNG and/or hydrogen available to this category of end-use customers.

Regarding the recommendation that gas customers be provided with the option to purchase RNG from their LDC or a third-party supplier, the Department has endeavored to develop a competitive natural gas supply market that would allow customers the broadest possible choice and provide all customers with an opportunity to share in the benefits of increased competition. See Natural Gas Unbundling, D.T.E. 98-32-B at 3, 4 (1999). We anticipate that there may be situations where customers would like to purchase RNG from their gas company or directly from a third-party supplier. We encourage LDCs to begin assessing customer interest in RNG and, if so, determine the associated demand load and begin developing educational and marketing material. While we support customer choice as it relates to RNG, we recognize that due to its nature and current technology, RNG is more expensive than conventional natural gas (Regulatory Designs Report at 25, 41). The inclusion of RNG-related costs in an LDC's supply portfolio costs—i.e., costs currently recovered under an LDC's seasonal cost of gas adjustment clause—would therefore increase the average cost of gas. To avoid any cross-subsidization issues, participation in such a program must be voluntary with all associated costs, including program administration costs, allocated and recovered solely from the participants. As we will not authorize a mechanism that would socialize the higher commodity cost of RNG, the Department expects that customers selecting RNG, regardless of whether it was procured from the LDC or a third-party supplier, will be responsible for the costs. We expect that the LDCs will inform potential customers of the cost of RNG, its lifecycle GHG emissions, and the likely bill impacts associated with their participation. To ensure that no costs associated with such a voluntary option are assigned to non-participants, the LDCs must keep a separate accounting of RNG costs and develop a voluntary RNG opt-in sales tariff outlining the provisions for service for Department review and approval. In summary, subject to the conditions above, we will allow the option for consumers to purchase RNG from an LDC or a third-party supplier.

The Department cautions, however, that RNG and hydrogen may require system upgrades due to the density of the fuels. If the LDCs need to upgrade their systems or incur additional interconnection and metering equipment costs to make these fuels available, all of the relevant system-upgrade costs, in addition to traditional costs borne by gas ratepayers, must be assumed by those who will take RNG supply and not by all customers. In summary, all costs associated with RNG are to be borne solely by utility shareholders or program participants.

The Department may review proposals for RNG or hydrogen pilot programs, as discussed below in Section VI.D. However, we agree with the Attorney General that RNG and hydrogen blending are new, unproven, and uncertain technologies. LDCs may research and assess these technologies, but until they prove to be a viable alternative to the business-as-usual model and support the Commonwealth's climate targets, any infrastructure costs associated with RNG and hydrogen will be the sole responsibility of the utility shareholders and not their customers.

D. Pilot and Deploy Innovative Electrification and Decarbonized Technologies

1. Introduction and Summary

The Regulatory Designs Report recommends that the LDCs pilot and deploy the following four technologies: (1) networked geothermal; (2) targeted electrification; (3) hybrid heating systems; and (4) renewable hydrogen (Regulatory Designs Report at 27-29). Further, the Regulatory Designs Report recommends that the Department develop guidance for review and approval of pilot projects and R&D programs, design additional cost recovery mechanisms, and track and report on performance metrics (Regulatory Designs Report at 29-30).

The Regulatory Designs Report explains that pilot opportunities for networked geothermal systems potentially could serve as strategic replacements for planned capital spending and be consistent with networked geothermal pilots approved for NSTAR Gas[50] and National Grid (gas);[51] however, the Regulatory Designs Report notes outstanding questions

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50 On October 30, 2020, the Department approved a networked geothermal demonstration project proposed by NSTAR Gas to evaluate the technology in a mixed-use, dense urban environment. D.P.U. 19-120, at 138-156.

51 On December 15, 2021, the Department approved a networked geothermal demonstration proposal from National Grid (gas). Boston Gas Company,

exist regarding the technical implementation, financing, and role of networked geothermal in avoiding gas infrastructure investments (Regulatory Designs Report at 27). The Regulatory Designs Report also recommends an investigation into the most optimal operation of hybrid heating systems to support both the gas and electric systems and potentially lower annual customer bills, avoid electric infrastructure costs necessary to meet heating demands, and lower GHG emissions through reliance on dispatchable winter peak generation resources (Regulatory Designs Report at 28). Finally, the Regulatory Designs Report recommends that LDCs pursue pilot opportunities to investigate the extent to which hydrogen can be added to their systems without the need for customer equipment or pipeline upgrades, engage in R&D opportunities related to the commercialization of synthetic gases, and explore certified natural gas, which may have lower upstream emission intensity (Regulatory Designs Report at 28-29).

The Regulatory Designs Report posits that an updated process for approval of pilot and R&D programs could facilitate the timely evaluation and deployment of decarbonized technologies better than a project-by-project approach (Regulatory Designs Report at 29).

D.P.U. 21-24, at 32-33 (2021). National Grid (gas) will prioritize the installation of networked geothermal systems that evaluate one or more of the following concepts: (1) the thermal performance and economics of shared loops serving a larger number of customers with more diverse load profiles than a networked geothermal project completed by its New York affiliate; (2) switching gas customers to geothermal energy as an alternative to leak-prone pipe replacement; (3) installing shared loops to manage local gas system constraints and peaks; and (4) installing shared loops to lower operating costs and GHG emissions for low-income customers and environmental justice populations. D.P.U. 21-24, at 3-4.

The Regulatory Designs Report explains that pilot and R&D programs could establish a process to track and report on performance metrics of interest, such as achievement of defined objectives; installation and service provider participation; customer education, interest and adoption experience; and role of the project in achieving decarbonization goals (Regulatory Designs Report at 30). The Regulatory Designs Report states that LDCs could recover the costs associated with additional pilots and R&D either through the local distribution adjustment clause or a new fully reconciling funding mechanism (Regulatory Designs Report at 30).

In this Order, we evaluate the potential of the four specific technologies recommended by the Consultants, both in the context of this proceeding and future potential investigations, pilot programs, and targeted deployments, and we address the regulatory framework that exists and that will evolve for the review and approval of pilot programs to examine emerging decarbonization technologies.

2. Summary of Comments

Commenters generally agree with the recommendation that the Department should streamline its review of pilot opportunities to facilitate more timely evaluation and deployment of electrification and decarbonized technologies (see, e.g., DOER Initial Comments at 16; CLF Initial Comments at 60; Acadia Center Initial Comments at 25). However, commenters disagree about which technologies, fuels, and end uses merit ratepayer-funded R&D (see, e.g., Attorney General Final Comments at 11-12; AIM Comments at 2; RMI Final Comments at 4; EDF Initial Comments at 1-3). To that end, the

Attorney General urges the Department to acknowledge the technical uncertainty of decarbonizing the building heating sector, calling for a framework that provides for fair consideration of the current and future technologies and commercial applications required to meet the Commonwealth's clean energy mandates (Attorney General Final Comments at 3-4).

Several commenters express support for the LDCs' approved networked geothermal pilots, arguing for the accelerated deployment of this technology (see, e.g., Sierra Club Final Comments at 11-12; CLF Initial Comments at 12; Climate Action Now Western Mass Comments at 2 (May 5, 2022); Mothers Out Front Massachusetts Comments at 1, 4 (May 2, 2022)). The Attorney General calls on the Department to open an investigation into the regulatory treatment of geothermal heat districts and alternative thermal technologies to examine possible regulation and ownership frameworks as the Department continues to learn about the costs, feasibility, and scalability of networked geothermal (Attorney General Initial Comments at 45-46). Similarly, HEET proposes a framework for the evolution of LDCs into thermal utilities, positing that pilots involving 100 customers or fewer could be approved by the Department within a month of filing (HEET Comments at 17, 22-32). The LDCs state that they consider networked geothermal to be a type of targeted electrification and would like the flexibility to pursue or expand their networked geothermal offerings, pending the receipt of successful pilot data (LDC Joint Comments at 67).

Numerous commenters call for R&D into other types of targeted electrification, including decommissioning of the gas system, that may demonstrate cost savings (see, e.g., CLF Initial Comments at 9, 55; DOER Final Comments at 16-17). The Attorney General calls for the adoption of comprehensive geographic distribution system and customer mapping,[52] in addition to an investment alternatives calculator to assist in reviewing traditional gas system capital investments (Attorney General Initial Comments at 22-24, 33-35; Attorney General Final Comments at 10-11). Similarly, DOER recommends that the Department require the LDCs to complete geographic mapping and marginal cost analyses before moving forward with any additional R&D proposals so that the LDCs can use these results in determining the appropriateness of any such projects (DOER Initial Comments at 14-15; DOER Final Comments at 7-10, 19-20).

Numerous commenters object to LDCs piloting alternative fuel blends (i.e., RNG, hydrogen, SNG) into their distribution systems, raising concerns about safety, affordability, GHG emissions, and leakage (see, e.g., Attorney General Initial Comments at 11-14; Acadia Center Initial Comments at 21; Sierra Club Initial Comments at 17; Massachusetts Medical Society Comments at 1-2). Other commenters acknowledge that alternative fuels may be necessary for the Commonwealth to reach its clean energy commitments, calling for R&D in various hard-to-electrify end uses including certain industrial processes (see, e.g., CLF Initial Comments at 61; Sierra Club Initial Comments at 15; City of Boston Initial Comments[53] at 1; Medical Area Total Energy Plant Comments at 1 (July 28, 2022)). The Attorney General

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52 The Department further discusses geographically planned approaches and gas/electric coordination topics below in Section VI.D and Section VI.G.

53 Comments of the Rev. Mariama White-Hammond, Chief of Environment, Energy, and Open Space, City of Boston (May 5, 2022).

recommends that any investment in unproven technologies such as RNG and hydrogen be viewed as imprudent today with the associated costs being borne entirely by utility shareholders (Attorney General Initial Comments at 32-33). Regarding proposals for new technologies or fuels, DOER argues that the LDCs must identify "go/no go benchmarks," including when to abandon a project or program if the results show that longer-term implementation would not be cost effective for ratepayers and/or achieve net-zero emissions in the most cost-effective manner (DOER Final Comments at 12).

3. Analysis and Conclusions

a. Introduction

Demonstration projects or pilots are well-established and evaluated vehicles for the introduction of emerging technologies into the existing framework of broadly deployed programs such as energy efficiency. In Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 20-150-A, updating its energy efficiency guidelines, the Department compiled directives from recent orders that addressed the appropriate process and standard of review for approval and changes to demonstration project proposals. D.P.U. 20-150-A at 22. The Department described a demonstration project as "a relatively small, self-contained endeavor, such as a pilot, that may transition to a core initiative or program," and further clarified demonstration project evaluation, budgetary, and cost-effectiveness considerations. D.P.U. 20-150-A at 24-25; Guidelines § 3.9.[54]

In this proceeding, numerous commenters agree that the Department should develop additional guidance for its review and approval of pilot projects and R&D programs in an effort to study and deploy innovative electrification and decarbonized technologies (see, e.g., Regulatory Designs Report at 27-30; DOER Initial Comments at 16; Attorney General Initial Comments at 24, 33). The Department strives to foster the innovation necessary to ensure the safe and reliable delivery of low-carbon energy in an equitable manner; at the same time, the Department must consider the potential customer bill impacts of any additional cost recovery mechanisms for pilots, as ratepayers in the Commonwealth already experience significant energy supply and programming costs. See, e.g., 2022-2024 Three-Year Plans Order at 220, 223. The Department maintains that pilots are valuable because they are small in scale and allow for the collection of distinct data and insights that will advance knowledge in a specific field. See, e.g., D.P.U. 21-24, at 26; Fitchburg Gas and Electric Light Company, D.P.U. 16-184, at 10-12 (2017).

The Regulatory Designs Report recommends that the LDCs pilot and deploy four specific technologies (Regulatory Designs Report at 27-29). As discussed below, the

54 The Department defines a demonstration project as a hard-to-measure offering, including pilots, limited in term and scope designed to provide the information required to assess its potential for measurable, cost-effective savings and benefits that can be scaled to be included in programs. Guidelines § 2.3. Demonstration projects are hard-to-measure offerings initially but are anticipated to have measurable savings and benefits at scale. Guidelines § 3.9.1.1.

Department welcomes networked geothermal and other targeted electrification technologies[55] in particular as promising decarbonization strategies and will require each LDC to identify pertinent demonstration projects in each of its service territories. In contrast, the Department is uncertain about the viability of hybrid heating and hydrogen technologies and their potential as economical long-term solutions for ratepayers, for the reasons we discuss below.

b. Hybrid Heating Systems

The Regulatory Designs Report recommends investigation into the optimal operation of hybrid heating systems, in support of both the gas and electric distribution systems (Regulatory Designs Report at 28). Specifically, the Consultants recommend further investigation of certain design elements for hybrid heating systems, such as the installation of integrated controls (Regulatory Designs Report at 28).[56]

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55 The Department emphasizes that pilot projects, including those for networked geothermal and other targeted electrification technologies, funded by gas ratepayers must benefit those ratepayers and not constitute cross-subsidization. See D.P.U. 19-120, at 147-148 (networked geothermal project must be designed in a manner to provide direct benefits to ratepayers whether through participation or in a manner that will generate findings to inform the scalability of networked geothermal for its existing gas customers).

56 The Consultants note that during the 2019-2021 Three-Year Plan term, program administrators created initial integrated controls specifications and requirements to ensure that heat pumps installed to augment existing systems operate efficiently, and that additional studies were proposed in the 2022-2024 Three-Year Plan term (Regulatory Designs Report at 28). “Program Administrators” are the LDCs as well as electric distribution companies and approved municipal aggregators who develop and administer energy efficiency programs under the Green Communities Act. St. 2008, c. 169. D.P.U. 20-150-A at 1.

Several commenters express skepticism about hybrid heating systems, urging the Department to reject the hybrid electrification scenario completely (see, e.g., Attorney General Technical Comments at 3, 19, 21; Acadia Center Initial Comments at 19-21; Sierra Club Initial Comments at 5).[57] As mentioned above, the Attorney General argues that the Pathways Report's promotion of a hybrid electrification pathway rests on unsound and unproven assumptions, and that the benefits of hybrid electrification on electric infrastructure additions can be attained by focusing on building electrification in the near term (Attorney General Technical Comments at 6-21).

The LDCs maintain that hybrid electrification is a practical and relatively low-challenge strategy and opportunity to achieve the Commonwealth's decarbonization objectives (LDC Joint Comments at 70). The LDCs argue that hybrid electrification technologies: (1) reduce the need for electric system build out; (2) mitigate costs and winter peaking; and (3) provide energy security benefits as a cold-climate backup system (LDC Joint Comments at 70-75). Other commenters argue that a hybrid electrification approach to decarbonization preserves optionality and elements of customer choice as renewable generation increasingly comes online (see, e.g., AIM Comments at 2; Shell USA, Inc.

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[57] As noted above, Section 77 of the 2022 Clean Energy Act explicitly prohibits the Department from approving any company-specific plan pursuant to D.P.U. 20-80 prior to conducting an adjudicatory proceeding with respect to such plan. St. 2022, c. 179, § 77. Therefore, at present, the Department will not endorse or reject any specific pathway or space heating technology.

Comments at 4-5; Tufts Medicine Lowell General Hospital Comments at 1; Lahey Hospital and Medical Center Comments at 1; SFE Energy Comments at 3).

The Department cannot reject or prohibit hybrid heating systems as an option for customers. It is, after all, the customer who chooses the type of heating system to install in the home or building. The Department shares the concerns expressed by numerous commenters, however, that a customer's retention of a gas furnace or boiler to serve exclusively as a cold-climate backup may not be necessary.[58] In the short term, hybrid heating could be used to support both the gas and electric systems and potentially lower annual customer bills, avoid electric infrastructure costs to meet heating demands, and lower GHG emissions through reliance on dispatchable winter peak generation resources (Regulatory Designs Report at 28). In the long term, however, it will be impractical to maintain the gas distribution system solely for backup furnaces in cold weather. The Department will therefore not approve the use of additional ratepayer dollars for hybrid heating system pilots and, as stated below, we expect LDCs to focus on targeted electrification and—pending the outcome of current pilots—networked geothermal projects to meet the long-term climate targets of the Commonwealth.

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58 The Department notes that research priorities for the LDCs as Program Administrators of the 2022-2024 Energy Efficiency Plan include studying residential hybrid heat pump controls, optimization, and metering impacts, in addition to requiring integrated controls for certain residential and income-eligible applications (See D.P.U. 21-120 through D.P.U. 21-129, Exh. 1, at 77; Exh. 1, App. H at 21, 57-60).

Nevertheless, the Department must ensure that the information contractors relay to customers who are deciding between hybrid and full-electrification technologies is both informative and correct. Therefore, the Department will require the LDCs to report on hybrid heating switchover practices in their first Climate Compliance Plan filings. This first Climate Compliance Plan report must include a discussion of the technical resources provided to contractors in the Mass Save heat pump installer network such as heat pump capacity and temperature point heuristics, and address any service area specific guidance that differs from cold-climate sizing and design trainings offered by common manufacturers. The Department fully expects that the LDCs as Program Administrators will continue to explore hybrid heat pump shared benefit and incentive structures, particularly related to LMI participants.

c. Renewable Hydrogen and RNG

The Regulatory Designs Report recommends that the LDCs pursue pilot opportunities to investigate the extent to which hydrogen and RNG can be blended safely into the LDC distribution system without the need for customer equipment or pipeline upgrades (Regulatory Designs Report at 28). The Consultants further note R&D opportunities related to the commercialization of synthetic gases and recommend investigating certified natural gas which may have reduced upstream emissions from the production of gas (Regulatory Designs Report at 28-29).[59]

[59] The Department discusses synthetic and certified gas commodity above in Section VI.C.

Numerous commenters express concern with potential emissions and leakage issues associated with hydrogen blending, with the Attorney General arguing for all investments in hydrogen to be viewed as imprudent, and borne entirely by shareholders (see, e.g., Attorney General Initial Comments at 32-33; EDF Initial Comments at 1-3). Other commenters note that alternative fuels such as hydrogen may be necessary for the Commonwealth to reach its clean energy commitments, calling for R&D in certain hard-to-electrify end uses such as industrial processes (see, e.g., CLF Initial Comments at 61; Sierra Club Initial Comments at 15; City of Boston Initial Comments at 1; Medical Area Total Energy Plant Comments at 1). The LDCs acknowledge that the GHG effects of leaked, non-combusted hydrogen are not well understood, and that very few studies are available on its global warming potential (LDC Joint Comments at 56, citing Pathways Report at 113).

The Department agrees that significant research is necessary before hydrogen feasibly could be injected into an LDC's distribution system. The Department notes that the states of New York, New Jersey, Maine, Rhode Island, Connecticut, and Vermont along with the Commonwealth of Massachusetts announced the submission of a proposal for a Northeast Regional Clean Hydrogen Hub[60] to the U.S. Department of Energy ("DOE") to compete for a $1.25 billion share of the $8 billion in federal hydrogen hub funding available as part of the Infrastructure Investment and Jobs Act, Pub. L. No. 117-58 (2021). In an announcement on October 13, 2023, DOE announced the first regional hydrogen hubs and the Northeast

60 See https://www.masscec.com/press/seven-states-northeast-regional-clean-hydrogen-hub-announce-submission-362-billion-proposal (last visited November 29, 2023).

Hydrogen Hub was not selected for funding.[61] The Department is optimistic that future funding opportunities may allow for the exploration of hydrogen R&D in the region without requiring additional ratepayer funds.

The Department also acknowledges, however, that there may be certain end uses, such as high-temperature industrial processes, that require a combustible molecule of a lower GHG emissions profile. In the short term, the Department will entertain hydrogen demonstration proposals for targeted end uses. Any proposals for hydrogen or RNG pilots, however, should include cost-effectiveness screening, and in the absence of cost-effectiveness screening, an appropriate analysis must support the potential of the proposal to deliver net benefits in the future. Guidelines § 3.9. Further, hydrogen and RNG demonstration project proposals must thoroughly explain how the targeted application is "hard to decarbonize," in addition to explaining electrification alternatives and alignment with the GWSA and the 2021 Climate Act. Further, RNG and hydrogen pilot proposals must take into consideration environmental justice populations and ensure that any such projects do not contribute to a decline of indoor air quality.

d. Networked Geothermal

Networked geothermal technology connects multiple, energy-efficient ground-source heat pumps ("GSHPs") to a loop system designed to provide heating and cooling to multiple buildings in a geographic area. The Department has found that: (1) geothermal networks

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61 See https://www.energy.gov/articles/biden-harris-administration-announces-7-billion-americas-first-clean-hydrogen-hubs-driving (last visited November 29, 2023).

have the potential to significantly reduce GHG emissions; and (2) geothermal demonstration projects designed to test the effectiveness and scalability of utility-owned geothermal networks have the potential to reduce current barriers to widespread adoption in furtherance of the Commonwealth's climate policies. D.P.U. 19-120, at 139.

Several commenters express support for networked geothermal technologies and their expedited deployment (see, e.g., Attorney General Initial Comments at 45-46; DOER Final Comments at 9, 15-16). The LDCs acknowledge that they consider networked geothermal to be a type of targeted electrification and would like the flexibility to pursue or expand their networked geothermal offerings, pending the receipt of successful pilot data (LDC Joint Comments at 67).

The Department commends the LDCs for exploring an innovative technology that has the potential to reduce GHG emissions and barriers to widespread deployment of clean heating technologies in furtherance of the Commonwealth's climate laws and policies. The Department notes the substantial progress in the construction of the Commonwealth's first utility-owned networked geothermal demonstration project in Framingham, with NSTAR Gas planning for the loop to be in operation prior to the 2023 heating season. See NSTAR Gas Company, D.P.U. 23-86, Exh. EVER-ANB/NLB-1, at 11.

Regarding the Attorney General's request to open an investigation into the regulatory treatment of geothermal heat districts and alternative thermal technologies, the Department concludes that opening an investigation at this time is premature. The Department shares the optimism expressed by stakeholders concerning the operation and management of the approved networked geothermal demonstrations, and eagerly awaits successful evaluation data concerning their costs, feasibility, and potential scalability.[62] Depending upon the results of that evaluation, the Department can be expected to move expeditiously to develop broader guidance for networked geothermal, which may require specific performance metrics and strategies to target benefits toward environmental justice populations.

e. Targeted Electrification

Several commenters support additional targeted electrification demonstration projects, in which a participant would disconnect from the gas distribution system and fully electrify space heating and appliance loads (see, e.g., CLF Initial Comments at 9; RMI Final Comments at 3). To that end, numerous commenters recommend that the LDCs complete comprehensive geographic system and customer mapping, in addition to marginal cost analyses to explore cost-effective alternatives to traditional gas investment (see, e.g., Attorney General Final Comments at 14-15; DOER Initial Comments at 14-15).[63]

The LDCs respond to this proposition by citing several factors that require evaluation before targeted electrification is undertaken on parts of their systems (LDC Joint Comments at 68). The LDCs indicate, for example, that removing gas service from certain parts of

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62 In addition, the Department has approved a settlement agreement in Eversource Energy/Bay State Gas Company, D.P.U. 20-59/19-140/19-141 at 61 (2020), that provided funding for the Attorney General and DOER to administer a geothermal microgrid pilot in the Merrimack Valley.

63 The Department further discusses comprehensive geographic distribution system and customer mapping below in Section VI.G below.

their systems may result in operational concerns regarding system pressures and flows elsewhere on their systems (LDC Joint Comments at 68). The LDCs also argue that decommissioning the gas distribution system would require greater education efforts, as removing gas service as an option for any of a customer's building needs will affect the viability of proposed targeted electrification options (LDC Joint Comments at 68). Generally, the LDCs raise concerns about the process, standards, and policies surrounding targeted electrification, while ensuring the safety and reliability of customers who choose to remain on the system (LDC Joint Comments at 68-69).

The Department is optimistic that targeted electrification through decommissioning parts of the gas system may serve as a promising approach to reaching the Commonwealth's GHG emissions targets; the Department also recognizes, however, that there are several operational constraints and unknowns as raised by the LDCs. To better understand these opportunities and constraints, the Department directs each LDC to work with the relevant electric distribution company to study the feasibility of piloting a targeted electrification project in its service territory. Each LDC, in coordination with the applicable electric distribution company, shall propose at least one demonstration project in its service territory for decommissioning an area of its system through targeted electrification. The LDC should target a portion of its system that suffers from pressure/reliability issues, leak-prone pipe, and/or that targets environmental justice populations that have borne the burden of hosting energy infrastructure. The Department expects the LDCs to engage with elected and appointed officials in the community, community-based organizations that work on energy, environment, labor, or ending poverty, and other interested residents. The Department directs each LDC to file its project proposal by March 1, 2026, for inclusion in its 2030 Climate Compliance Plan, working with its relevant electric distribution company and Program Administrator as necessary.[64]

f. Demonstration Project Process

In reviewing a proposed demonstration project, the Department considers the: (1) reasonableness of the size, scope, and scale of the proposed project in relation to the likely benefits to be achieved; (2) adequacy of the evaluation plan; (3) extent to which there is appropriate coordination among Program Administrators; and (4) bill impacts to customers, among other things. Guidelines § 3.9.1. Demonstration projects are not required to be cost effective at the initial testing and evaluation stage; however, an evaluation report at a demonstration project's conclusion requires detailed analyses of actual project costs and benefits, in addition to projected costs and benefits were the project to be delivered as a program at scale. Guidelines §§ 3.9.1.1, 3.9.2. In absence of cost-effectiveness screening,

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[64] The Department has found that, while pursuing energy and demand savings through strategic electrification, the Program Administrators must seek to reduce GHG emissions and minimize ratepayer costs. 2022-2024 Three-Year Plans Order at 84. Splitting incentives between gas and electric Program Administrators may mitigate bill impacts and produce a more equitable sharing of costs and benefits between gas and electric ratepayers. The Department notes that Program Administrators already are required to address fully how they considered a split incentive for both large traditional custom projects and large strategic electrification projects that involve offsetting natural gas consumption in its three-year energy efficiency plan, term report, and any applicable mid-term modification proposals. Liberty Utilities (New England Natural Gas Company Corp., D.P.U. 22-94, at 14 (2022).

detailed program descriptions and appropriate analysis must support the potential of a demonstration project to deliver net benefits in the future. Guidelines § 3.9.1.2.

The Department recognizes that both geothermal demonstration projects that have come before us required multiple proceedings, such as separate proposal, implementation, and cost-recovery filings, in addition to project-level evaluation studies.[65] See, e.g., Boston Gas Company, D.P.U. 20-120, Interlocutory Order on Proposed Demonstration Projects (December 11, 2020); NSTAR Gas Company, D.P.U. 21-53, Order on Phase I NSTAR Gas Company's Implementation Plan (January 4, 2022); NSTAR Gas Company, D.P.U. 22-125, Stamp Approval (December 5, 2022). Inasmuch as the Department had not reviewed a geothermal network proposal prior to 2020, however, such a proposal was considered a matter of first impression. The Department determined that these additional proceedings were therefore necessary to protect participating consumers, set the appropriate budgets, and maintain general oversight as the LDCs use ratepayer dollars to explore innovative solutions in support of Massachusetts' GHG emissions reductions targets. D.P.U. 19-120, at 138, 141, 148-149, 154; D.P.U. 21-53, at 8-9.

The Department has general supervisory authority over gas and electric companies, and must make all necessary examination and inquiries to keep itself informed as to the

65 The Department acknowledges that multiple proceedings may serve as a barrier to meaningful engagement and participation by the public, and, to that end, the Department opened an investigation into procedures for enhancing public awareness of and participation in its proceedings. Notice of Inquiry by the Department of Public Utilities on its own Motion into Procedures for Enhancing Public Awareness of and Participation in its Proceedings, D.P.U. 21-50 (2021).

condition of the respective properties owned by such corporations, and the manner in which they are conducted with reference to the safety and convenience of the public. G.L. c. 164, § 76. The Department anticipates that the desired streamlining will occur as demonstration projects in support of the Commonwealth's GHG emissions reductions targets become more routine and as the LDCs understand what is expected of them in meeting the Department's standard of review.

Accordingly, the Department concludes that no further "streamlining" of its demonstration project review is required at this time, and that the LDCs have received sufficient guidance and cost-recovery avenues for researching and deploying innovative electrification and decarbonization technologies. The Department fully recognizes the financial and technological uncertainties that LDCs face in reaching the Commonwealth's mandated decarbonization targets; to minimize ratepayer costs, however, we continue to require that innovative technologies be rooted in cost-effectiveness and be offered in a cost-efficient manner.

Any demonstration project proposals related to innovative technologies must include detailed implementation plans and terms and conditions that are acceptable to and protective of participants. Each LDC seeking to demonstrate a new technology must propose novel objectives that will reasonably result in quantifiable GHG emissions reductions, and each LDC will be required to provide updates in its Climate Compliance Plan reports. As circumstances change, the Department may consider an alternative framework to incentivize the deployment of decarbonization technologies, as necessary.

E. Manage Gas Embedded Infrastructure Investments and Cost Recovery

1. Introduction and Summary

As discussed above in Section V.A, most of the pathways modeled predict declines in the number of LDC customers and system utilization over time (Regulatory Designs Report at 31-32). The Consultants raise two main concerns surrounding the issue of declining customers and throughput, namely the resulting higher costs for customers remaining on the natural gas system, and a mismatch between how infrastructure costs are currently recovered and the predicted system utilization (Regulatory Designs Report at 31-32). To mitigate the potential impacts associated with the recovery of embedded infrastructure costs and declining system usage, the Consultants recommend finding ways to minimize or avoid gas infrastructure investments where possible, pre-approval of non-GSEP investments, revisions to existing line extension policies, and accelerated depreciation (Regulatory Designs Report at 32-40).

a. Minimize Capital Investments

The Consultants recommend that the Department and LDCs develop a framework to examine opportunities to minimize or avoid gas infrastructure projects, while continuing to maintain safe and reliable service (Regulatory Designs Report at 32-33). The Regulatory Designs Report encourages geographically targeted electrification where possible as a way to address embedded infrastructure cost issues, as well as investigating various NPAs to replace non-cathodically protected steel, cast-iron, and wrought iron, and other aged pipe with new pipe (Regulatory Designs Report at 33). The Consultants acknowledge that these options are not without barriers, as targeted electrification requires all customers in an area to agree to terminate gas service and switch to electric service, and there are costs associated with switching (Regulatory Designs Report at 33). NPAs discussed include energy efficiency measures, demand response solutions, electrification, and networked geothermal systems (Regulatory Designs Report at 33-34).

b. Pre-Approval

The Consultants recommend the Department establish a process to review and pre-approve LDC capital investment plans relating to non-GSEP investments (Regulatory Designs Report at 34). They suggest conducting holistic, long-term capital planning that aligns safety and reliability investments with the Commonwealth's decarbonization targets (Regulatory Designs Report at 34). The Consultants propose reviewing LDC capital plans every three years—similar to the review process for energy efficiency plans—and that the process should evaluate changes in forecasted demand driven by decarbonization goals (Regulatory Designs Report at 34).

c. Line Extensions

Another recommendation for managing the concerns around embedded infrastructure is to revise the standards associated with line extensions and investments to serve new customers (Regulatory Designs Report at 34-36). The Consultants note that currently the standard for serving new customers is that existing customers must not subsidize the cost to serve new customers, and that to the extent the incremental revenues of the customer addition are not equal to or greater than the associated costs, the difference must be paid by the customer in the form of a CIAC (Regulatory Design Report at 36). The Consultants identify four potential changes to the current line extension policy: (1) shortening the investment payback period; (2) reducing customer revenues supporting the new investments; (3) increasing the target rate of return on the investments; and (4) requiring customers to guarantee the revenues supporting the incremental costs (Regulatory Designs Report at 36).

d. Accelerated Depreciation

Rather than the current practice of utilizing straight-line depreciation, the Consultants recommend accelerated forms of depreciation, such as the Units of Production method or implementing shorter service lives, to better align the recovery of infrastructure costs with the anticipated utilization and anticipated customer migration (Regulatory Designs Report at 37-40). The Consultants suggest that while accelerated forms of depreciation increase costs in the short term, the associated depreciation costs should remain stable compared to continued use of the straight-line method, which will result in increased future costs if system utilization declines (Regulatory Designs Report at 37-38). Accelerated deprecation is presented as not only a means of mitigating affordability and equity concerns, but also a way to mitigate concerns related to unrecovered rate base as customers leave the gas system by recovering costs in an accelerated fashion (Regulatory Designs Report at 38-39).

2. Summary of Comments

A number of commenters specifically argue that line extensions and new customer additions should cease as soon as possible, citing health concerns, the potential for stranded assets, and the ability to achieve net-zero emissions (see, e.g., McCord Comments at 3

(May 6, 2022); Muzzy Comments at 1 (May 6, 2022) ("Muzzy Comments"); PLAN Final Comments at 6; RMI Initial Comments at 12-13; Robinson Comments at 1 (May 4, 2022)). Other commenters express general concerns regarding stranded assets associated with increased capital investments, and some urge a transition away from investments in fossil fuels (see, e.g., Archbald Comments at 1 (May 6, 2022); Armstrong Comments at 1 (May 4, 2022); Boston Common Asset Management Comments at 2 (May 6, 2022); Burdick Comments at 1 (May 6, 2022); C. Rose Comments at 1 (May 4, 2022); Royce Comments at 1 (May 2, 2022)). Several commenters support implementing opportunities to minimize or avoid gas infrastructure projects generally (see, e.g., Acadia Center Initial Comments at 24); CLF Initial Comments at 9).

LEAN contends that furthering capital investments and any proposals to accelerate cost recovery will only increase financial risks and create affordability issues for low-income customers in particular (LEAN Initial Comments at 10, 18). Alternatively, the Attorney General suggests that the Department conduct a review of existing tariff provisions and line extension policies, as there is no current uniform model or costing matrix to assess the cost-benefit analysis of line extensions (Attorney General Initial Comments at 32); Attorney General Final Comments at 16). More specifically, the Attorney General states the Department should determine whether the current CIAC model is consistent with state policies and goals, reflects anticipated investment recovery, and results in mostly free extensions for new customers (Attorney General Initial Comments at 32). The LDCs acknowledge that not all utilities handle line extensions in a uniform way and do not oppose a collaborative review of the current models or the development of a common framework as proposed by the Attorney General (LDC Joint Comments at 93).

In addition to the suggested review of CIAC models and line extension policies, the Attorney General recommends that the Department retain consultants or work with utilities to develop an "investment alternatives calculator" that would review and compare the expected costs of new gas system investments with the short- and long-term costs of alternative solutions (Attorney General Initial Comments at 33-35; Attorney General Final Comments at 11). The Attorney General contends that a properly designed investment alternatives calculator would provide a set of prescribed assumptions for the cost of carbon, a range of values for the cost of gas commodity, the cost of avoided GHG emissions, and the cost of alternative technologies (Attorney General Initial Comments at 33-34)

Regarding depreciation, Acadia Center, CLF, and others argue that accelerated depreciation is worth investigating, and DOER contends that a geographic marginal cost analysis to address decommissioning plans should be required before accelerated depreciation is allowed (see, e.g., Acadia Center Initial Comments at 24; CLF Initial Comments at 54; DOER Initial Comments at 17; RMI Initial Comments at 13). CLF also suggests that investigations into any depreciation changes should begin promptly, as any delays could increase the risk of rate shock when changes are implemented, and that depreciation rates should reflect the utilization of different assets with different lifetimes (CLF Initial Comments at 49, 53).

The Attorney General asserts that accelerated depreciation inappropriately shifts market and climate policy risk from utilities to ratepayers while increasing the cost of gas service (Attorney General Initial Comments at 35-36). She suggests it is unrealistic for utilities to continue to invest in gas infrastructure without regard to market risks and decarbonization goals, and that the Department may choose to treat future infrastructure investments differently from those made historically (Attorney General Initial Comments at 36). The Attorney General contends the Department should order LDCs to file information on the magnitude of potential stranded costs and work to establish clear cost recovery timelines or guidelines to balance the costs and responsibilities of possible stranded assets (Attorney General Initial Comments at 35-37; Attorney General Final Comments at 16). The Town of Hopkinton opposes the adoption of accelerated depreciation, arguing that it shifts cost recovery to taxpayers from the LDCs and ratepayers (Town of Hopkinton Comments at 3-4 (May 6, 2022)). The LDCs disagree with the Attorney General's assessment regarding the shifting of risks, and instead argue that accelerated depreciation addresses affordability concerns for current and future customers while maintaining a safe and reliable system (LDC Joint Comments at 86). The LDCs argue that they must continue to make investments to maintain the gas system, and that the regulatory compact entitles utilities to an opportunity to earn a reasonable return on, and a return of, their prudent investments (LDC Joint Comments at 87). The LDCs also disagree with DOER's assertion that consideration of accelerated depreciation should be delayed until the completion of a marginal cost analysis addressing decommissioning plans, arguing that it would be subject to significant uncertainty and complexities (LDC Joint Comments at 87-88).

3. Analysis and Conclusions

a. Pre-Approval and Capital Investments

The Regulatory Designs Report recommends that the Department review and pre-approve certain future LDC capital investments as part of the reporting and planning process going forward in order to continue providing safe and reliable gas service (Regulatory Designs Report at 46). In the instant proceeding, the Department is not persuaded that pre-approval of investments is appropriate at this time. We observe that there are extensive federal and state regulations intended to ensure the safe maintenance and operation of the natural gas pipeline system, which include safety standards and mandated program improvements. The Department will not interfere with the mandates of the federal and state regulations. See, e.g., 49 C.F.R. §§ 192.907, 911, 1005, 1007; 220 CMR 101.00. The Department does, however, recognize that achieving state climate change goals necessarily requires the minimization of stranded investments to the extent possible. The Consultants recommend encouraging NPAs as alternatives to replacing aged pipes and/or installing new mains. The Attorney General argues that the Department should adopt a robust alternatives analysis or an "investment alternatives calculator" to ensure that any investments made represent the best alternative available at the time (Attorney General Initial Comments at 33; Attorney General Final Comments at 11). The Department agrees that consideration of NPAs will be an essential part of the regulatory landscape, and that companies should begin examining opportunities to minimize investments that may contribute to future stranded costs. As described in Section III above, the recoverability of additional investment in natural gas infrastructure will require an analysis of whether such investments are consistent with state emissions reduction targets and the thorough evaluation of NPAs. As part of any future cost recovery proposals, LDCs will bear the burden of demonstrating that NPAs were adequately considered and found to be non-viable or cost prohibitive in order to receive full cost recovery.[66]

b. Line Extensions

As discussed in Section III, the Commonwealth's climate laws, which include a 2050 GHG emissions reduction mandate and interim targets, require LDCs and the Department to move beyond a "business as usual" approach to system planning and expansion. Accordingly, the Department agrees with the Consultant and commentor suggestions that the standards for investments to serve new customers be examined and revised. The Attorney General specifically recommends that the Department address the standard for line extensions, along with other ratemaking policies, as part of a gas ratemaking regulatory reform in a separate proceeding or working group (Attorney General Final

66 The Attorney General suggests the use of a "investment alternatives calculator" to evaluate NPAs. The Department agrees that stakeholders should have the opportunity to review not only individual NPA analysis but the underlying assumptions and inputs. The Department therefore directs that in conducting the cost-benefit analysis underlying the consideration and evaluation of NPAs, the LDCs consult with stakeholders prior to submitting an NPA analysis for Department review and adjudication.

Comments at 16). The LDCs express a willingness to develop collaboratively a common framework for evaluating new service connections and a review of existing CIAC and internal rate of return ("IRR") models (LDC Joint Comments at 92-93). The Department directs all LDCs to begin reviewing existing tariffs, policies, and practices related to new service connections to determine: (1) the number of *de facto* free extension allowances; (2) whether current models and policies accurately reflect the anticipated income and timeframe over which the capital investments will be recovered; and (3) whether existing state policies are inconsistent with current practices by incentivizing new customers to join the gas distribution system and allowing LDCs to extend their systems through plant additions.

The Department recognizes that certain statutory and legislative changes may be necessary going forward. In NSTAR Gas Company, D.P.U. 22-107 (2022), in the context of a proposed extension of natural gas service to the Town of Douglas, several parties and participants expressed concern that Section 3 of the Gas Leaks Act, which mandates that the Department review and approve proposals designed to increase the availability, affordability, and feasibility of natural gas service for new customers, is inconsistent with the Commonwealth's GHG emissions reduction targets and climate policies. D.P.U. 22-107, at 6-9, 12. Section 3 was enacted by the Legislature in 2014. D.P.U. 19-120, at 464. Prior to any approval and implementation of a program proposed under Section 3, the Department must review the company's determination that a main or service extension is economically feasible and review the gas company's CIAC policy and methodology. St. 2014, c. 149,

§ 3(a); D.P.U. 19-120, at 456. In D.P.U. 22-107, the Department found that the state's recent climate legislation neither repealed nor amended Section 3; however, we recognize the inherent conflict between the express goals of these statutes given that Section 3 encourages investments in new main and service extensions and increased use of natural gas, while climate legislation mandates a reduction in GHG emissions. See D.P.U. 19-120, at 464. For the Department to pursue fully its mandate to prioritize reductions in GHG emissions along with safety, security, reliability of service, affordability, and equity as directed by the Legislature in the 2021 Climate Act, we recommend that the Legislature repeal Section 3 of the Gas Leaks Act to eliminate any potential conflict of laws.

With respect to line extensions and applications specifically pursuant to G.L. c. 164, Section 30,[67] the Department determines whether a proposal is reasonable. As discussed in D.P.U. 22-107, we have found this includes the overarching consideration of the public interest, defined generally as requiring that there be no adverse impacts on existing natural gas customers. D.P.U. 22-107, at 3-4. In reviewing future applications, the Department will examine the public interest in the context of our broader climate mandates. In doing so,

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67 The Department reviews petitions for authorization to expand a gas distribution company's service territory pursuant to G.L. c. 164, § 30, which states:

> The [D]epartment may, after notice and a public hearing, authorize a gas or electric company to carry on its business in any town in the commonwealth other than the town named in its agreement of association or charter, subject to sections eighty-six to eighty-eight, inclusive, and it may purchase, hold and convey real and personal estate in such other town necessary for carrying on its business therein.

we note that Section 30 does not require that the Department grant petitions in those circumstances where such a grant would not adversely impact existing customers. See D.P.U. 22-107, at 4. We also note that in D.P.U. 22-107, the Department found that the company had demonstrated that an alternative electrification approach was economically unviable, and that the expansion of services into the Town of Douglas was reasonable and consistent with the public interest. D.P.U. 22-107, at 15. While Section 30 does not expressly require a company to evaluate alternatives to expanding its gas system, going forward the Department will take the evaluation of alternatives into consideration along with any impact on achieving the state's climate targets. D.P.U. 22-107, at 15. Finally, although the adjudication of a specific standard of review is outside the scope of this proceeding, the Department anticipates that its consideration of a petition pursuant to Section 30 will presume a requirement of consistency with an LDC's Climate Compliance Plan, as discussed in Section VI.G.

c. Accelerated Depreciation

There is general consensus among the LDCs and stakeholders that the issue of depreciation and stranded assets must be examined. While stakeholders differ as to the exact approach to deal with the issue, the Department agrees that the matter is important and must be investigated. As an initial step, the Department directs all LDCs to conduct a comprehensive review that includes a forecast of the potential magnitude of stranded investments. As part of this review, the LDCs must identify the impacts of accelerated depreciation proposals and identify potential alternatives to accelerated depreciation.

The Consultants and LDCs specifically reference the "Units of Production" method of accelerated depreciation as a way of aligning cost recovery of capital investments with system utilization, noting that it is a method recognized by the National Association of Regulatory Utility Commissioners ("NARUC"), as well as the option of implementing shorter asset service lives (Regulatory Designs Report at 38). The Department notes there are various options to consider with respect to accelerated depreciation, and the LDCs should not limit their review to any one method such as the Units of Production method, as each has its own inherent benefits and limitations (see, e.g., Regulatory Designs Report at 38; NARUC Depreciation Manual at 52-53; 57-61). Accelerated depreciation methods currently are not used for regulatory purposes, with the straight-line method primarily utilized in utility depreciation studies (NARUC Depreciation Manual at 61). The Department previously has recognized, however, that there is a fundamental transition underway in the gas industry in Massachusetts, and further investigation of cost recovery of existing infrastructure investment is required. The goal of the review should be not only assessing the magnitude of stranded costs, but also to investigate ways to address cost recovery while balancing ratepayer and shareholder risk going forward in a way that adequately reflects system costs, shareholder awareness of risk, and realistic expectations of the future, while addressing customer affordability and equity concerns.

F. Evaluate and Enable Customer Affordability

1. Introduction and Summary

The fifth regulatory recommendation focuses on evaluating and enabling customer affordability as customers transition away from reliance on the gas system to decarbonized technologies. The Consultants caution that each of the identified decarbonization pathways raise cost considerations for customers as well as associated equity challenges, which will require regulatory and policy interventions to mitigate impacts on customers (Regulatory Designs Report at 40). In particular, the Consultants explain that given the magnitude of potential cost impacts, and the rate and equity implications associated with progress toward electrification, there is a need to expand the scope of the current cost recovery mechanisms for LDCs (Regulatory Designs Report at 41). The Consultants therefore recommend a specific set of regulatory designs and policy changes to address these concerns, which we discuss below (Pathways Report at 100-108; Regulatory Designs Report at 40-45).

a. Cost and Equity Implications of the Pathways

The Consultants highlight that the upfront costs required for customers to convert appliances and heating systems from natural gas to electricity are a significant barrier for customers to migrate off the gas system (Pathways Report at 105-106). The Consultants further state that when a growing number of customers transition off the gas system, customers who remain on the system will experience increasing energy costs that they must absorb (Regulatory Designs Report at 40; Pathways Report at 106). Absent regulatory changes, the Consultants conclude the remaining customers will see higher rates due to varying increases in commodity or delivery costs[68] (Regulatory Designs Report at 41). The Consultants maintain that by 2050, some of the higher electrification pathways may result in unrealistic costs imposed on customers from $30,000 to more than $70,000 per customer per year (Pathways Report at 107). Pathways with more moderate levels of electrification result in less significant cost shifting, yet still yield costs per customer expected to be 40 percent to 50 percent above the reference case by 2050 (Pathways Report at 107).

In addition to affordability challenges, the pathways present equity challenges, including cost shifting between migrating and non-migrating customers and between rate classes, and potential disproportionate impacts on low-income customers and customers designated as environmental justice populations (Regulatory Designs Report at 40; Pathways Report at 106). The Consultants explain that customers who are unable to fund the high upfront costs of switching to decarbonized technology (especially non-migrating customers who qualify for low income-rates and those who are designated as environmental justice populations) or otherwise face challenges in adopting clean technologies (i.e., the hard-to-electrify commercial sector) are more likely to remain stranded on the gas system and shoulder the growing costs (Pathways Report at 29, 106-109). The Consultants state that

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68 According to the Consultants' projections, certain pathways that allow for higher continued gas system utilization (i.e., "Efficient Gas Equipment" and "Low Electrification") will experience increased commodity cost of renewable gas in the system, while others that allow for lower gas system utilization (i.e., "High Electrification") will see increases in delivery costs due to customers departing the gas system and leaving behind uncollected embedded gas infrastructure costs to be recovered over fewer customers and/or therms (Pathways Report at 101; Regulatory Designs Report at 41).

low-income customers remaining on the gas system likely will spend an increasingly higher share of their income on energy, from approximately seven percent to more than 15 percent in 2050 (Pathways Report at 101-102).

In addition, the Consultants caution that the pathways present various equity considerations with respect to existing infrastructure retirements, new energy infrastructure construction, and the decommissioning of LDC infrastructure, including municipal tax base impacts, service interruptions and road closures associated with prolonged and significant electric industry or alternative technology construction, and decommissioning of LDC infrastructure (Pathways Report at 108). The Consultants explain that policies will need to address and mitigate, to the extent possible, impacts on environmental justice and low-income populations associated with siting and construction of energy infrastructure as well as potential decommissioning of any LDC facilities. The Consultants state that these mitigation policies are particularly important for environmental justice populations, which generally are concentrated in communities already hosting energy infrastructure (Pathways Report at 108).

b. Recommended Regulatory and Policy Interventions

The Consultants propose to address affordability and equity concerns through a set of specific regulatory design recommendations, which focus on understanding and minimizing the impacts of decarbonization on customers (Regulatory Designs Report at 42). These regulatory design recommendations include identifying and quantifying transition costs, evaluating the impacts of transition costs on customers, and exploring alternative cost recovery mechanisms and securitization as methods for mitigating affordability issues

(Regulatory Designs Report at 42, 45). In addition, the Consultants suggest that policy interventions such as targeted incentives aimed at promoting a more equitable transition to clean technologies are warranted (Regulatory Designs Report at 20, Pathways Report at 108). Ultimately, the Consultants conclude that the magnitude and pace of electrification associated with a particular pathway will impact LDCs and the Department's ability to develop and implement regulatory policies that mitigate potential cost shifts and associated equity issues (Pathways Report at 108).

First, the Consultants recommend developing a framework to identity and quantify transition costs (i.e., uncollected costs from customers who have departed the gas system, costs associated with design and implementation of the regulatory reforms,[69] workforce transition costs, and costs associated with restructuring or realignment of gas supply portfolios) (Regulatory Designs Report at 42). The next step should be to evaluate the impact of those transition costs on customers under the various pathways (Regulatory Designs Report at 42).[70]

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69 These proposed regulatory reforms include geographically targeted electrification, non-pipeline solutions, coordinated planning efforts between electric and gas utilities, and accelerated depreciation (Regulatory Designs Report at 42).

70 The Consultants explain that under some pathways, such as 100 percent gas decommissioning, the transition costs grow quickly and have a substantial impact on customer rates much earlier in the decarbonization pathway, while under other pathways, such as hybrid electrification, the transition costs grow more slowly and have a substantial impact on rates later in the decarbonization pathway (Regulatory Designs Report at 42).

The Consultants next recommend mitigating transition costs by evaluating alternative approaches to cost recovery, such as charging customers leaving the gas system an exit fee or migration fee ("migration charge"),[71] and a statewide recovery mechanism through electric surcharges ("transition charge") (Regulatory Designs Report at 42). The first approach suggests a migration charge for customers leaving the gas system to cover costs that were incurred to serve them but not collected (Regulatory Designs Report at 42-43).[72] According to the Consultants, this would minimize the cost shift to customers remaining on the system as well as minimizing the potential for non-recovery of embedded costs (Regulatory Designs Report at 43). The second approach of charging transition charges seeks to align the benefits of decarbonization with the transition costs through sharing the transition costs more broadly with those who benefit from the transition (Regulatory Designs Report at 43). The Consultants acknowledge that the mechanism underlying this approach requires considerable review and evaluation, including its implications on LDC customers and, more broadly, on those who would pay for the transition costs, but they suggest that the process could start with establishing a fund and continue with attempts to identify other funding sources (Regulatory Designs Report at 43). The Consultants assert that the substantial transition costs

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71 The Consultants refer to this fee as a "migration fee," while some commenters refer to the charge as an "exit fee." The Department uses the term migration charge, which has the same meaning as migration fee and exit fee, and references the terms used by commenters when summarizing comments.

72 The Consultants posit that this option likely would require legislative approval given the charge would be based on LDC costs charged to non-LDC customers (Regulatory Designs Report at 42).

associated with each pathway require a cost recovery mechanism consistent with the scope and scale of such costs (Regulatory Designs Report at 42).

The Consultants' final recommendation is to evaluate the use of securitization as a method to finance transition costs and lower a utility's borrowing costs, which, in turn, decreases the amount customers will have to repay, and allows both parties to benefit directly from the bond market (Regulatory Designs Report at 45).[73] The Consultants acknowledge that securitization poses the challenge of requiring a secure revenue stream, whereas the revenue stream under the decarbonization pathways is subject to significant uncertainty (Regulatory Designs Report at 45). The Consultants suggest that a possible, albeit untested, solution to this uncertainty would be through charges on both gas and electric bills (Regulatory Designs Report at 45).

In addition to the above set of regulatory design recommendations, the Consultants introduce a few policy interventions they claim are needed to address affordability and regulatory concerns. First, to address the burden of upfront capital costs of appliances, as well as the costs associated with decarbonization in the building sector (e.g., implementing building shell retrofits), the Consultants suggest that expanded policies aimed at providing additional customer incentives should be established (Pathways Report at 102, 106-107; App. 1, at 57).

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[73] The Consultants state that securitization has been used in the utility industry to finance the recovery of extraordinary costs (e.g., wildfire mitigation costs in California, coal plant decommissioning costs in New Mexico, and storm costs in Texas), serving to minimize the impacts on customer rates (Regulatory Designs Report at 45).

Next, the Consultants suggest that a means of mitigating the unintended consequences of inequitable cost shifting is to provide incremental incentives to low-income and environmental justice populations to promote decarbonization (Pathways Report at 108). In addition, the Consultants suggest that incentives designed to benefit both landlords and renters would help address the current misalignment of interests between these parties, especially for pathways with higher levels of customer transitions (Pathways Report at 108). Further, the Consultants caution that the pathways present various equity issues related to both existing infrastructure retirements and new energy infrastructure construction, including municipal tax base impacts, service interruptions and road closures associated with prolonged and significant electric industry or alternative technology construction, and decommissioning of gas infrastructure (Pathways Report at 108). Importantly, environmental justice populations are generally over-represented in communities already hosting energy infrastructure (e.g., LDC on-system LNG and propane assets). Given that each pathway has a significant level of energy infrastructure construction, the Consultants suggest that policies will need to specifically address and mitigate the disproportionate impacts on environmental justice and low-income populations associated with siting and constructing energy infrastructure as well as the decommissioning any LDC facilities (Pathways Report at 108).

2. Summary of Comments

Several commentors expressed affordability concerns, particularly for LMI customers (see, e.g., Attorney General Initial Comments at 50; DOER Initial Comments at 15; LEAN Initial Comments at 18; NCLC Initial Comments at 32; HEET Comments at 7). Several stakeholders call for the prioritization of LMI customers to ensure an equitable transition and protect those customers from bearing the increased energy burden associated with electrification (see, e.g., NCLC Initial Comments at 32; LEAN Final Comments at 2-3; Sierra Club Final Comments at 12). Stakeholders generally agree that LMI customers are less likely to leave the gas system and, therefore, may be disproportionately impacted by higher energy bills (see, e.g., Acadia Center Initial Comments at 22; LEAN Initial Comments at 17). To that end, several commentors suggest that the LDCs should consider rate mechanisms to help protect LMI ratepayers from high energy burdens and potential rate increases (see, e.g., Attorney General Initial Comments at 52; DOER Initial Comments at 15; LEAN Initial Comments at 18).

The Attorney General argues that the current gas regulatory framework does not protect LMI customers and customers in environmental justice populations from the increasingly high energy burdens that will disproportionately impact these customers as more ratepayers leave the gas system in the transition to a net-zero future (Attorney General Initial Comments at 46-47, 52; Attorney General Final Comments at 3-4). The Attorney General asserts that the high upfront investment required to transition to alternatives, such as heat pumps, creates inequities for LMI customers as these households often lack savings, disposable income, and access to credit, which prevents them from affording clean energy alternatives (Attorney General Initial Comments at 47-48). The Attorney General adds that likewise renters may be poorly positioned to participate in and benefit from the energy transition as renters often are responsible for heating bills yet have no control over the heating system and a landlord may not be motivated to make necessary upfront investments (Attorney General Initial Comments at 48; Attorney General Final Comments at 3-4). The Attorney General further observes there is a disproportionate impact to health and safety experienced in certain communities (e.g., due to pollution or the siting of energy infrastructure), including environmental justice populations (Attorney General Initial Comments at 50).

The Attorney General argues that protection for LMI ratepayers must be directionally consistent with reducing dependence on natural gas and should minimize the risk that customers unable to migrate end up with a disproportionate share of transition, embedded, or stranded costs (Attorney General Initial Comments at 52). To this end, the Attorney General recommends that the Department consider adopting a rate mechanism to protect LMI ratepayers from high energy burdens and from potential rate increases related to climate investments by both the gas and electric distribution companies, such as implementing a cap on the amount an LMI ratepayer is billed (Attorney General Initial Comments at 52). The Attorney General further recommends that the Department provide targeted support to LMI customers and customers in environmental justice populations when programs are designed to facilitate opportunities for residents to access cleaner energy alternatives (Attorney General Initial Comments at 52; Attorney General Final Comments at 17).

Several commenters disagree with implementing a migration charge as suggested by the Consultants (see, e.g., Acadia Center Initial Comments at 24-25; RMI Initial Comments at 3; Sierra Club Initial Comments at 18-19; CLF Final Comments at 6). Acadia Center agrees that customer affordability issues should be addressed through a Department investigation of various cost recovery options, but does not believe exit fees are the appropriate approach (Acadia Initial Comments at 24-25).

Sierra Club argues that a migration charge is unfair and undermines the Commonwealth's GHG emissions reduction goals by contradicting incentives to leave the gas system (Sierra Club Initial Comments at 18-19). Sierra Club further contends that this approach fails to account for system costs to which customers contributed but from which they did not benefit (e.g., system expansions and system upgrades to deal with growing demand in certain geographic areas), and questions whether customers would be compensated for those excess contributions when they leave the gas system as well (Sierra Club Initial Comments at 19). Sierra Club also argues that electric ratepayers should not be burdened with gas system transition costs (Sierra Club Initial Comments at 19). Sierra Club suggests that this approach would make the cost of electrification relatively more expensive and would affect not only the customer economics of electrifying from gas, but also of electrifying fuel oil and propane use (Sierra Club Initial Comments at 19).

According to Sierra Club, the best way to minimize low-income energy burdens is to fully electrify low-income housing as part of a high electrification strategy given that the Pathways Report shows that energy burdens of low-income customers would be lowest for those who fully electrify (Sierra Club Initial Comments at 22; Sierra Club Final Comments at 12). Sierra Club states that while it is important to implement policies such as low-income rates to mitigate impacts on those low-income customers left on the gas system, the priority should be implementing policies and funding programs to support low-income electrification to ensure low-income customers are not left behind in the transition to clean energy (Sierra Club Initial Comments at 22; Sierra Club Final Comments at 12). LEAN also supports protection of low-income customers from rate increases under the pathways and advocates for an increase to low-income discounts (LEAN Initial Comments at 17; LEAN Final Comments at 2-3).

CLF also argues against imposing a migration charge or transition fee on customers leaving the gas system (CLF Final Comments at 6). CLF contends that doing so would essentially serve as a penalty for transitioning to decarbonized technologies (CLF Final Comments at 6). Further, according to CLF, such a framework would ensure that only those who can afford to pay the fee will be able to make the choice to use clean energy options, leaving the most vulnerable residents who are unable to afford the costs to transition to clean energy stranded on an increasingly high-cost gas system (CLF Final Comments at 6). In addition, CLF submitted a "Scoping a Future of Gas Study," which recommends that utility analyses must account for the differences between customer classes and reflect the impact of each scenario on customers in each category, including low-income ratepayers, moderate-income ratepayers, and renters within the residential class, as well as different types of commercial buildings and industrial consumption (CLF Initial Comments at 38). CLF suggests that LDCs must track the rate and bill impacts of each energy transition scenario on customers with reduced ability to make infrastructure choices in their homes, such as LMI households and renters, and find ways to mitigate the effects of any inequitable outcomes (CLF Initial Comments at 38). The analyses for customer affordability must compare overall costs associated with the use of gas as a "bridge" fuel versus direct transition to electricity (CLF Initial Comments at 39). CLF recommends that LDCs also should consider that customers might switch from pipeline gas to delivered fuels if pipeline service becomes uneconomic, and include recommendations to mitigate any negative effects resulting from such choices (CLF Initial Comments at 39).

DOER agrees with the Consultants that it is necessary to protect customers, particularly low-income customers and those in environmental justice populations, from rate shocks by evaluating decarbonization-specific rate structures (DOER Initial Comments at 9, 11). DOER argues that the Department should require the LDCs to conduct a geographic marginal cost analysis to identify where transitioning to cleaner technologies provides significant benefits, which includes recommendations for mechanisms (e.g., new rate structure proposals for future tariff proceedings or for future legislative or regulatory action) to help protect low-income residents (DOER Initial Comments at 15). DOER asserts that LDCs must balance affordability concerns for customers against continuing to make necessary investments in the gas system to ensure safety and reliability (DOER Final Comments at 19).

The LDCs indicate support for the Commonwealth's climate goals and contend that customer choice should be at the center of any strategy to meet those goals as individual decisions about when and how to adopt electrification and efficiency measures will affect the nature, scale, and magnitude of electric and gas system transformations (LDC Joint

Comments at 93-94, citing Pathways Report at 15). The LDCs support the hybrid electrification pathway because it results in lower energy system costs, providing an incentive for customers to adopt hybrid heating systems (LDC Joint Comments at 75). The LDCs support the Consultants' suggestions for potential rate designs, such as a new hybrid heating rate class and critical peak pricing, to incentivize customers to adopt or remain on hybrid heating systems (LDC Joint Comments at 75). To ensure customer equity, LDCs are considering potential financial transfers from electric utilities to gas utilities as an approach to fund transition costs (LDC Joint Comments at 75). The LDCs assert this arrangement recognizes the multiple benefits of maintaining gas system functionality, including better utilization of the electrical system, avoidance of significant electrical system upgrade costs, and the maintenance of an alternative energy source in the event of blackouts (LDC Joint Comments at 75). The LDCs argue that achieving the levels of electrification modeled in each pathway will require significant customer education efforts, as well as development of supportive policy initiatives and market transformation activities that help customers overcome the upfront cost barriers to electrification (LDC Joint Comments at 94-95).

3. Analysis and Conclusions

a. Introduction and Summary

In opening this investigation, the Department sought to examine strategies to enable the Commonwealth to move into its net zero GHG emissions energy future while simultaneously safeguarding ratepayer interests. As detailed by the Consultants and LDCs and reinforced by several stakeholder comments, customers are expected to see considerable impacts through the affordability and equity implications of the transition to clean energy alternatives. Namely, customers will face challenges with respect to the upfront costs necessary to invest in clean technologies, rate increases for a declining number of customers remaining on the gas system, and resultant equity impacts, especially for LMI ratepayers and environmental justice populations.

In discharging our responsibilities under G.L. c. 25, the Department must prioritize affordability and equity in addition to safety, security, reliability of service, and reductions in GHG emissions to meet statewide emissions limits and sublimits. G.L. c. 25, § 1A. As electrification efforts expand, ensuring affordability and equity is of particular importance to avoid overburdening customers financially, particularly those who already bear higher burdens in terms of not only costs but other cumulative impacts. The Department acknowledges that the ability to meet these goals will depend on a variety of factors, including the magnitude and pace of customer transition, and legislative and regulatory changes. The Department remains committed to ensuring that its future regulatory policies are aimed at addressing barriers to expeditious customer transition to decarbonized energy options, while mitigating challenges with affordability and equity.

Throughout this proceeding, numerous stakeholders and individuals raised concerns regarding the ability of customers to afford the costs of the transition away from gas, as well the potential inequitable impacts to customers, especially those most vulnerable. The Consultants, as well as several stakeholders, propose a host of solutions to address these issues. Upon examination of the challenges and proposed strategies related to affordability identified during this proceeding, the Department has determined that further investigation is necessary and herein sets forth several areas for future evaluation that will focus on informing the strategies and any necessary regulatory changes to balance affordability and equity with the need to transition into a clean energy future as quickly and aggressively as is practicable. We discuss these areas of future investigation below.

b. Transition Costs

With respect to transition cost considerations, the Department recognizes that the increasing number of gas customers leaving the gas system likely will result in higher rates for those customers remaining on the system. The Department shares commenters' concerns regarding barriers preventing LMI customers from transitioning away from gas, while those same customers would bear a disproportionate energy burden by remaining on the gas system. We agree that new regulatory support and strategies will be needed to minimize the negative implications of this potential cost shifting and to maximize affordability.

The Department supports the Consultants' suggestion that an appropriate starting point is the development of a framework to identify transition costs and quantify these costs to understand the full scope of the cost impacts associated with the various decarbonization strategies, and then to evaluate the impact of those costs on ratepayers. The Department envisions that this framework should, at minimum, include identifying and quantifying the following transition costs: (1) uncollected costs from customers who have departed the gas system; (2) costs associated with design and implementation of regulatory reforms, including geographically targeted electrification, NPAs, coordinated planning efforts between electric and gas utilities, and accelerated depreciation; (3) workforce transition and training costs; and (4) costs associated with restructuring or realigning of gas supply portfolios (Regulatory Designs Report at 42).

Once quantified, the impact of transition costs on ratepayers, particularly LMI customers and environmental justice populations, should be evaluated fully. Importantly, this evaluation should encompass a broad range of considerations, including but not limited to: (1) bill impacts by customer class (short and long term as well as percentage of cost increase relative to household income); (2) GHG emissions reductions; (3) public health and safety; and (4) equity[74] under the various pathways. The Department is interested in DOER's recommendation that the LDCs conduct a geographic marginal cost analysis to identify where transitioning to cleaner technologies provides significant benefits, including potential mechanisms (e.g., new rate structure proposals for future tariff proceedings or for future legislative or regulatory action) to help protect LMI ratepayers. As discussed in Section VI.E above, the Department favors a robust alternatives analysis, and we see a geographical marginal cost analysis to be a potentially valuable and informative part of that process. As suggested by the Attorney General, the Department will prioritize consideration

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74 In this context, evaluation of equity considerations should include impacts on LMI customers, environmental justice populations, renters, and people of color, both in terms of energy burden and energy-related health and safety impacts. An equity analysis should consider the disproportionate and inequitable distribution of burdens and benefits that currently exist as well as future projections.

of any impacts that result in disproportionate and inequitable distribution of burdens and benefits when making any future regulatory decisions.

c. Alternative Cost Recovery

The Department agrees that we should evaluate and consider alternative cost recovery mechanisms. The Consultants suggest implementing migration and transition charges, along with financing transition costs through securitization, as potential cost recovery mechanisms to alleviate the increasing burdens on customers as more and more leave the gas system. Several commenters express support for types of mechanisms that help mitigate cost and equity impacts to customers, but also argue that implementing the Consultants' proposed mechanisms is inappropriate.

While the Department acknowledges the potential benefits of implementing a migration charge or exit fee for migrating off the gas system—such as reducing the costs that will shift to the remaining gas customers and minimizing the potential for non-recovery of embedded costs—the potential burdens and impacts on those customers and their decision to adopt clean alternatives remain unknown and untested. The Department is concerned that charging a fee to exit the gas system may disincentivize some customers from pursuing electrification. Similarly, while the Department acknowledges the potential benefit that securitization methods could yield (i.e., in terms of lowering borrowing costs and reducing customer rate shocks), the full scope of the impacts on customers and the gas and electric systems remains to be seen.[75] For these reasons, the Department declines to adopt the proposed alternative cost recovery mechanisms at this time and we will examine other cost recovery mechanisms in a future investigation.

Lastly, the Department agrees with several commenters that there is a need to adopt a rate mechanism aimed at protecting LMI customers from high energy burdens and potential rate increases as they transition from gas to electricity. As mentioned in Section VI.B above, the Green Communities Act directs that 20 percent of three-year energy efficiency plan budgets be allocated to low-income energy efficiency. G.L. c. 25, § 21(b)(1). We determine that there should be additional policies and programs to support low-income electrification to ensure low-income customers are not left behind in the transition to clean energy and, in fact, benefit in the near-term from electrification opportunities. The Department encourages the LDCs to work with the Energy Efficiency Advisory Council, including LEAN, to explore strategies to better reach underserved populations and hard-to-reach customers, including renters and landlords, LMI customers, and environmental justice populations. The Department also previously directed the LDCs to weatherize prior to or as part of an electrification project to ensure that overall energy consumption will decrease, while minimizing ratepayer bill impacts, particularly for LMI customers, for purposes of acquiring all cost-effective energy efficiency under the Green Communities Act. 2022-2024

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[75] The Department notes that while G.L. c. 164, §1H, provides that the Department shall approve an electric company's securitization plan that maximizes rate affordability to ratepayers, the statute does not explicitly apply to LDCs.

Three-Year Plans Order at 107-108. An enhanced incentive structure that includes weatherization for low-income and environmental justice population customers in addition to incentives for heat pump conversions will ensure a reduction in energy consumption and minimize bill impacts. The LDCs should encourage, through education and enhanced incentives, proper weatherization of all customer homes in advance of heat pump installation. LDCs should also ensure that contractors properly size heat pumps prior to installation. Failing to do so potentially increases energy costs for customers. 2022-2024 Three-Year Plans Order at 107-108.

Further, we acknowledge the Recommendations of the Climate Chief, Melissa Hoffer, developed pursuant to Executive Order No. 604, §3(b), which recommends that the Department "prioritize any rate reform necessary to ensure that electric bills will be affordable for all households, particularly those with low and moderate incomes."[76] As noted in Section III above, the Department will investigate this issue further as we evaluate methods to ensure affordability and equity in light of higher energy burdens on LMI customers.

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[76] Hoffer, Melissa, Office of Climate Innovation and Resilience, "Recommendations of the Climate Chief pursuant to Section 3(b) of Executive Order No. 604," pages 40-43 (October 23, 2023), available at: https://www.mass.gov/doc/recommendations-of-the-climate-chief-october-25-2023/download (last visited November 29, 2023).

G. Develop LDC Transition Plans and Chart Future Progress

1. Introduction and Summary

The sixth regulatory recommendation includes developing transition plans and evaluating progress toward the Commonwealth's climate targets. The Consultants state that the transition toward achieving climate targets will require (1) periodic reporting and (2) an iterative planning process that reflects lessons learned and new developments (Regulatory Designs Report at 46). The Consultants identify the following reporting and planning processes for inclusion in the new LDC transition plans:

1) Evaluation of LDC transition plan progress toward achievement of climate goals and addressing challenges;

2) Review and pre-approval of future LDC capital investments with a focus on necessary gas system replacements and identification of strategic opportunities to avoid new gas infrastructure through electrification and alternative options;

3) Establish a framework to review and optimize cross-coordination planning between gas and electric utilities;

4) Establish a framework for review and approval of cost recovery mechanisms for LDC capital investments and pilot projects;

5) Evaluation of customer affordability metrics;

6) Evaluation of key initiative data such as number of renewable natural gas customers, GHG emissions calculations, rates and bill impacts, and impacts on environmental justice populations with each plan filing; and

7) Incorporation of performance metrics and incentives to align LDCs' financial incentives with the goals of the Commonwealth (Regulatory Designs Report at 46-47).

Each LDC filed a Net Zero Enablement Plan, an initial transition plan for meeting the Commonwealth's 2050 goals (Framework and Overview at 17). The LDC Net Zero

Enablement Plans are designed to continue energy efficiency efforts consistent with the three-year energy efficiency plans, and to advance decarbonization and the Consultants' recommended regulatory designs in the short term. (Framework and Overview at 17). Included in the LDC transition plans is a proposed Model Tariff that would allow the LDCs to recover costs associated with their respective Net Zero Enablement Plans (Framework and Overview at 18-19). The LDCs seek Department approval of a framework for future iterations of the Net Zero Enablement Reports and the Model Tariff (Framework and Overview at 18-19). Each LDC proposes to file a Net Zero Enablement Plan on a three-year cycle, to align with the three-year energy efficiency cycle, using a five-year and ten-year planning horizon (Framework and Overview at 18). The Consultants note that GSEP capital investments would not be included in the transition plans because there is a process in place for Department review and approval for such expenditures (Regulatory Designs Report at 46). The LDCs propose that the Department review their initial and future three-year transition plans pursuant to the following standard of review: "The LDC's transition portfolio is reasonably designed to contribute to the reduction of GHG emissions to meet net-zero emissions by 2050, without compromising the safety, reliability and affordability of service offered to current customers" (Framework and Overview at 18).

2. Summary of Comments

a. Comprehensive and Coordinated Planning

Most commenters agree that comprehensive planning is needed to guide future investments and meet decarbonization objectives. The Attorney General recommends that the

Department take several steps to support LDC comprehensive planning such as: (1) requiring LDCs to file a comprehensive geographic distribution system mapping report; (2) implementing an investment alternatives calculator;[77] (3) mandating an alternatives analysis for approval of LDC proposals for alternative sources of methane or combustible gas; (4) directing LDCs to file plans that demonstrate the achievement of required GHG emissions reductions; and (5) reviewing LDC forecast and supply planning to better align GHG emissions reduction requirements (Attorney General Final Comments at 10-13). The Attorney General explains that without a full map of the gas system, the regulatory framework would continue to perpetuate piecemeal planning and siloed decision making which may impact the cost-effective achievement of net zero emissions by 2050 (Attorney General Final Comments at 10). The Attorney General maintains that such a map could help identify areas that are best suited for targeted electrification (Attorney General Final Comments at 14). DOER also supports requiring LDCs to submit a geographic distribution system map (DOER Final Comments at 10).

In addition, commenters agree that coordinated planning between gas and electric distribution system companies is necessary. The Attorney General recommends that the Department require electric distribution company participation in gas system investment proceedings (Attorney General Final Comments at 15). The Attorney General contends that the Department cannot adequately evaluate any proposed investment without joint electric and

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[77] We address the suggestion of an investment alternatives calculator in Section VI.E.

gas planning (Attorney General Final Comments at 15). Other commenters such as Acadia Center and CLF oppose having LDCs lead the transition plans (Acadia Center Final Comments at 2; and CLF Final Comments at 7). Acadia Center and CLF argue that the LDCs have a financial interest in maintaining the gas system, which creates a conflict of interest in leading the transition plans (Acadia Center Final Comments at 2; CLF Final Comments at 7). CLF avers that LDCs should be treated as stakeholder participants in the "future of gas," while Acadia Center recommends implementing an independent planning authority to lead coordinated planning (CLF Final Comments at 7; Acadia Center Final Comments at 1; Acadia Center Initial Comments at 27-28). Public commenters conveyed support for developing transition plans, but many expressed concerns with the proposal that the LDCs lead the transition.

The LDCs disagree with Acadia Center's recommendation to create a third-party planning authority to oversee the transition plans (LDC Joint Comments at 78). The LDCs argue that creating a new third-party planning authority would conflict with prior Department precedent and the rights and obligations conferred upon utility companies by law and statute (LDC Joint Comments at 78). In particular, the LDCs posit that the Department has long deferred to the judgment and expertise of regulated utility companies when it comes to operating and maintaining their systems (LDC Joint Comments at 80, citing Boston Gas Company and Colonial Gas Company, D.P.U. 13-78, at 13 (2014)). Moreover, the LDCs maintain that it is appropriate for utilities to develop their own investment plans because they bear the responsibility of maintaining a safe and reliable service that is compliant with all federal and state regulatory and statutory requirements (LDCs Joint Comments at 81). Regarding specific analytical constructs for evaluating potential gas network investments proposed by the Attorney General and DOER (e.g., investment alternatives calculator or geographic mapping and marginal cost analysis), the LDCs argue such tools would reduce network planning to consideration of selected quantifiable parameters and, therefore, would be unable to capture the broad range of considerations that are required to make coordinated investment decisions (LDC Joint Comments at 82, citing Exh. DPU-Comm 7-2).

b. Limiting Incentives for Gas System Growth

Several commenters propose recommendations regarding GSEPs. The Attorney General asserts that the Department should consider climate objectives as part of GSEP review and require LDCs to demonstrate that the proposed investment is the least-cost alternative to improve safety and reduce leaks (Attorney General Initial Comments at 30). Additionally, the Attorney General proposes that the Department form a working group to make recommendations for potential changes to GSEPs (Attorney General Attorney General Initial Comments at 44). Similarly, DOER contends that LDCs should be required to address how specific GSEP investments correlate with a parallel geographical marginal cost analysis (DOER Final Comments at 18). DOER, Sierra Club, and CLF agree with revising the current GSEP process so investments in gas infrastructure can be minimized to the greatest extent practicable (DOER Final Comments at 17; CLF Initial Comments at 8; Sierra Club Initial Comments at 20). Several commenters echoed the importance of minimizing further gas system investments (see, e.g., HEET Comments at 8; LEAN Initial Comments at 10-11;

Muzzey Comments at 1). Commenters cited concerns regarding stranded assets and perpetuating the use of fossil fuel gas through gas system investments (see, e.g., RMI Initial Comments at 11; Werlin Comments at 1 (May 6, 2022); Lipke Comments at 1 (May 6, 2022)). Other commenters called for the end of both gas line extensions and the addition of new gas customers to the system (see, e.g., HEET Comments at 33; McCord Comments at 3; PLAN Initial Comments at 4).

The LDCs reiterate that the proposed transition plans exclude GSEP-related investments because there already is a process in place for Department gas system review and approval (LDCs Joint Comments at 81, citing Regulatory Designs Report at 46). The LDCs maintain that their respective GSEPs are consistent with the Gas Leaks Act and note that the Department consistently has found that the replacement of aging infrastructure under GSEPs achieves the goals of improvements in public safety, infrastructure reliability, and the reduction of lost and unaccounted for ("LAUF") natural gas. (LDC Joint Comments at 85, citing Fitchburg Gas and Electric Light Company, D.P.U. 20-GSEP-01, at 9 (2021)). Additionally, the LDCs note that they already are required to show that their respective GSEPs reduce emissions through annual filings with MassDEP (LDC Joint Comments at 85). The LDCs do not object to evaluating possible modifications to GSEPs as part of a working group provided they have adequate representation (LDC Joint Comments at 85).

Other recommendations are intended to further disincentivize gas system growth. For example, the Attorney General avers that LDCs should no longer be permitted to recover costs for marketing related to promoting gas service (Attorney General Initial Comments at 41). The Attorney General argues that these costs are not aligned with the Commonwealth's decarbonization goals and therefore expansion advertising should no longer be funded by ratepayers (Attorney General Initial Comments at 41). Similarly, the Sierra Club argues that incentives for gas appliances should be phased out (Sierra Club Initial Comments at 21). The Attorney General makes an additional recommendation to revise existing performance-based ratemaking ("PBR") mechanisms to establish incentives and disincentives designed around the gas utilities' progress in compliance with the Climate Act mandates (Attorney General Initial Comments at 40-41). The Attorney General states the Department should consider directing each LDC to submit revised PBR plans instead of waiting for the LDC to file its next base rate case (Attorney General Initial Comments at 40-41).

The LDCs disagree with the Attorney General's recommendation to revise the PBR mechanism (LDC Joint Comments at 88). The LDCs explain that PBR generates a level of revenue for a company to run its business, similar to an annual allowance to cover business operations, which enables the company to make system investments and attain operational and capital efficiencies (LDC Joint Comments at 89). According to the LDCs, these efficiencies create savings which are passed on to customers (LDC Joint Comments at 89). Additionally, the LDCs maintain that the existing PBR framework is not inherently inconsistent with progress toward decarbonization (LDC Joint Comments at 89). The LDCs argue that it is not necessary to revise the existing PBR because a new framework that aligns incentives with decarbonization still would apply with or without the current PBR framework (LDC Joint Comments at 89).

c. Net Zero Enablement Plans

Many commenters request that the Department reject the LDCs' individual Net Zero Enablement Plans and associated Model Tariff (see, e.g., Sierra Club Final Comments at 4; NCLC Initial Comments at 20; CLF Final Comments at 6). Some commenters express concerns that the proposed Net Zero Enablement Plans are biased, inaccurate, profit-driven, and ineffective to adequately transform energy use (Donaldson Comments at 1 (May 6, 2022); NCLC Initial Comments at 14-16; Sierra Club Final Comments at 13-14). In addition, other commenters contend that the Model Tariff is premature and that it is unfair for utilities to offer a product, such as RNG, as a tariffed utility service (see, e.g., Attorney General Initial Comments, App. C at 3-4; SFE Energy Comments at 3-4 (May 6, 2022)). The Attorney General criticizes the Net Zero Enablement Plans, contending that the LDCs are resisting change by seeking to maintain gas infrastructure (Attorney General Initial Comments, App. C at 2). The Attorney General proposes that the Department open a planning docket for the purpose of ensuring LDC compliance with climate mandates before considering the proposed Net Zero Enablement Plans (Attorney General Initial Comments, App. C at 3).

DOER recommends that the Department require the LDCs to develop more detailed three-year plans that propose decarbonization regulatory actions, evaluation of previous metrics, and recommendations for future plans (DOER Initial Comments at 13). DOER proposes that the Net Zero Enablement Plans should include the following: (1) a geographic mapping and marginal cost analysis to demonstrate the interaction of multiple strategies; (2) a demonstration of cost considerations; (3) enhanced proposals for regulatory actions to support decarbonization; and (4) metrics as a tool to evaluate successful strategies (DOER Initial Comments at 14). The LDCs maintain that each proposed Net Zero Enablement Plan pursues a portfolio of the various decarbonization pathways analyzed by the Consultants in an effort to meet the Commonwealth's targets while maintaining safety and reliability (LDC Joint Comments at 17). The LDCs request that the Department review and approve the individual Net Zero Enablement Plans and Model Tariff (LDC Joint Comments at 17).

3. Analysis and Conclusions

a. Introduction

The LDCs developed individual transition plans that articulate their role in supporting the Commonwealth's achievement of its climate mandates. The LDCs specifically propose to implement transition plans that include: (1) joint gas and electric planning; (2) periodic reporting; and (3) a Model Tariff to facilitate recovery of costs associated with the Net Zero Enablement Plans (Regulatory Designs Report at 46-47). The LDCs maintain that it is appropriate for utilities to develop their own transition plans and oppose recommendations to implement an investment alternatives calculator or geographic mapping report (LDC Joint Comments at 81-82). As we have stated from the beginning of this investigation, rather than selecting a single pathway for decarbonization, the Department will focus on creating a regulatory planning framework that is flexible, protects customers, and considers a suite of electrification and decarbonization technologies to facilitate the transition. Here we identify certain strategies and processes that will allow the Department and stakeholders to collect and evaluate information, establish common metrics and assumptions, and refine reporting review procedures to maintain and accelerate momentum toward achievement of the Commonwealth's climate targets. Consistent with our "whole of DPU" approach, these will include LDC reporting requirements, utilization of existing working groups and other forums, convening of technical conferences and additional working groups as necessary, and further investigation and adjudicatory proceedings within the Department.

b. Comprehensive and Coordinated Planning

The LDCs propose to establish a process for coordinated planning between gas and electric utilities (Regulatory Designs Report at 46). The Department agrees that coordinated and comprehensive planning between electric and gas utilities is needed to facilitate the energy transition. Gas and electric infrastructure planning will be necessary as consumers transition from using fossil fuel-based heating systems to electric heat pumps. We note that going forward, evaluation of any proposed investments will have to take place in the context of joint electric and gas system planning. The Department emphasizes that joint electric and gas utility planning must occur in a broad stakeholder context so that the LDCs and electric distribution companies exclusively are not defining the process and outcome. The LDCs and electric distribution companies should consult with stakeholders regarding such a joint planning process that, while it is not Department led, may lead to proposals for Department review. We will continue to monitor and define these processes in future proceedings, as necessary.

Next, the Department addresses the practicality of requiring a comprehensive map of the gas distribution network. The Attorney General asserts that a map of all gas system infrastructure will better enable the Department to evaluate proposed gas system investment and alternatives (Attorney General Initial Comments at 23-24). The Department in Section III and Section VI.E above expressed its support of a robust alternatives analysis, for the first time mandating that LDCs must include and demonstrate analysis of alternatives as a prerequisite for cost recovery of infrastructure investments. As to the requirement of a gas system infrastructure map, the Department seeks to balance the need for comprehensive and useable information with the nature of the extensive critical energy infrastructure information ("CEII") inherent in such an undertaking, which is required by public records law to be protected from public disclosure.[78] We therefore decline to order public filing of such mapping with the Department in a Climate Compliance Plan or otherwise. We will, however, explore appropriate means of facilitating such information sharing without compromising CEII.

The Department finds that it would be inappropriate to issue any further directives that could impact potential changes to GSEPs here. The 2022 Clean Energy Act required the Department to convene a stakeholder working group to develop recommendations and

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78 G.L. c. 66, § 6A(e); G.L. c. 4, § 7(26)(n).

legislative changes to align the gas system with statewide emissions limits, as well as encourage the development of geothermal systems. St. 2022, c. 179, § 68. The GSEP working group has met several times since its initial meeting in April 2023.[79] Each of the LDCs, as well as many of the parties to this proceeding, is participating in the GSEP working group process, and most of the topics raised by the Attorney General and other stakeholders are being explored in that forum. The GSEP working group is expected to produce its findings and recommendations to the Legislature by the end of the year.

c. Climate Compliance Plans

The Department appreciates the LDCs' efforts to design the initial Net Zero Enablement Plans. As a threshold matter, Section 77 of the 2022 Clean Energy Act dictates that the Department shall not approve any company-specific plan in this investigation prior to conducting an adjudicatory proceeding with respect to such plan. St. 2022, c. 179, § 77. Therefore, while the LDCs' Net Zero Enablement Plans lay out the companies' strategies to achieve compliance with climate objectives mandates,[80] which may inform the regulatory framework we seek to establish here, we cannot approve such a plan or a Model Tariff

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79 See https://www.mass.gov/info-details/gseps-pursuant-to-2014-gas-leaks-act (last visited November 29, 2023).

80 The LDCs explain that certain pathways evaluated in the Net Zero Enablement Plans, such as efficient gas equipment installation, may build on the three-year plan activities by offering additional incentives, complementary measures, or implementation practices that further advance efficient gas equipment installations, but that do not fall within the parameters of the Department's precedent for cost-effectiveness applicable to energy efficiency sectors, programs, or core initiatives (Exh. DPU-Comm 1-11).

without full adjudication. This proceeding is an investigation and not an adjudicatory proceeding. Consistent with the legislative directive, the Department will review and approve company-specific plans in subsequent adjudicatory proceedings.

To that end, the Department directs each LDC to file individual Climate Compliance Plans every five years, with the first such Plan being due on or before April 1, 2025.[81] Each Climate Compliance Plan should expand on previous Net Zero Enablement Plans by demonstrating how each LDC proposes to: (1) contribute to the prescribed GHG emissions reduction sublimits set by EEA for both Scope 1[82] and Scope 3[83] emissions; (2) satisfy customer demand safely, reliably, affordably, and equitably using known and market-ready technology available at the time of the filing; (3) use pilot or demonstration projects to assist

81 Subsequent Climate Compliance Plans would be due in 2030, 2035, and 2040. The plans should include a five- and ten-year planning horizon.

82 The U.S. Environmental Protection Agency ("EPA") defines Scope 1 emissions as "direct greenhouse emissions that occur from sources that are controlled or owned by an organization." Scope 1 and Scope 2 Inventory Guidance, available at https://www.epa.gov/climateleadership/scope-1-and-scope-2-inventory-guidance (last visited November 29, 2023).

83 The EPA defines Scope 3 emissions as emissions that "result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain." Scope 3 Inventory Guidance, available at https://www.epa.gov/climateleadership/scope-3-inventory-guidance (last visited November 29, 2023).

in identifying investment alternatives; (4) incorporate the evaluation of previous metrics[84]; and (5) implement recommendations for future plans.

Each electric distribution company operating in an LDC's service area will be required to participate in the Climate Compliance Plan gas planning process.[85] Each Climate Compliance Plan should detail the total investment required and should also include a description of at least one alternative method to meet the required emissions reductions, providing the estimated costs for the considered alternative, and a demonstration that the proposed plan is superior to the alternative. To track compliance with the Commonwealth's interim emissions reduction deadlines, each LDC will be required to file an informational Climate Act Compliance Term Report Filing nine months after each interim deadline (i.e., 2025, 2030, 2035, 2040) indicating whether or not the LDC achieved the required emissions reductions.

d. Climate Compliance Incentives

The LDCs state that the planning and evaluation process could be used to design performance metrics and incentives to align the LDCs' financial incentives with the Commonwealth's goals (Regulatory Designs Report at 47). A PBR mechanism can provide such an incentive for an LDC to take actions aligned with the Commonwealth's climate

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84 Evaluation of previous metrics would not be applicable to the first Climate Compliance Plan filed.

85 The Climate Compliance Plans should also include customer, stakeholder, and community input where practicable.

policy and mandates to reduce its sales of methane gas through a series of measures to encourage gas efficiency, demand response, and electrification, as well as reducing LDC system and customer emissions of methane and carbon dioxide. In recent Orders, the Department has approved a PBR framework for LDCs, recognizing that there is a fundamental evolution taking place in the natural gas local distribution industry in Massachusetts.[86] Currently, the Department requires a utility seeking approval of an incentive proposal like PBR to "demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates and reduced administrative burden in regulation."[87] To better align gas PBRs with the Commonwealth's long-term future of the gas system in a net-zero 2050 economy, the Department finds that it should amend the existing PBR framework to establish incentives and disincentives reflecting the gas utilities' progress toward compliance with the Climate Act mandates, and achievement of their approved Climate Compliance Plans. Accordingly, the Department directs the LDCs to propose climate compliance performance metrics in their next PBR filings.

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86 See, e.g., NSTAR Gas Company, D.P.U. 19-120, at 56; Boston Gas Company, D.P.U. 20-120, at 66-67 (2021).

87 See NSTAR Gas Company, D.P.U. 19-120, at 59.

VII. CONCLUSION

The Department herein has set forth a regulatory strategy for pursuing an energy future that begins to move the Commonwealth beyond gas and toward its climate objectives. As we have detailed, this will include new reporting and analysis requirements, utilization of existing working groups and other forums, convening of technical conferences and additional working groups as necessary, and further investigation and adjudicatory proceedings within the Department. Going forward, the Department will seek to facilitate a safe, orderly, and equitable transition for the LDCs and their customers through these processes while pursuing the Commonwealth's 2050 GHG emissions reductions mandate and interim targets.

VIII. ORDER

Accordingly, after due consideration, it is

ORDERED: That the Massachusetts gas local distribution companies shall comply with the directives contained in this Order.

By Order of the Department,

James M. Van Nostrand, Chair

Cecile M. Fraser, Commissioner

Staci Rubin, Commissioner