EB-2022-0157

Enbridge Gas Inc. Compendium for Examination of Dr. Heather McDiarmid

Modifications to Attachment #2 of Dr. MacDiarmid's "Evidence regarding stage 2 analysis and gas alternatives for greenhouses" updated October 18, 2023

1. Attachment #2 NPV calculation including the carbon tax as assumed by Dr. McDiarmid, 15-year NPV including upfront cost: **$4,012 NPV**.
2. Attachment #2 NPV calculation with carbon tax set at zero (0), 15-year NPV including upfront cost: **$-3,516 NPV**.
3. Attachment #2 NPV calculation with carbon tax frozen at the 2023 level, 15-year NPV including upfront cost: **$-128 NPV**.

Pathways to Decarbonization

A report to the Minister of Energy to evaluate a moratorium on new natural gas generation in Ontario and to develop a pathway to zero emissions in the electricity sector.

DECEMBER 15, 2022

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Assessing a Pathway to a Decarbonized Future

The Pathways scenario looks at the time frame for decarbonizing Ontario's electricity system in the context of high electricity demand based on substantial electrification in other sectors.

Using the same supply base case as the Moratorium scenario, Pathways focused on 2050, assuming non-emitting resources would be available for 25 years for solar and 30 years for biomass and wind from their commissioning dates. Hydroelectric facilities were assumed to be available for the duration of the study time frame. In this scenario, up to the year 2035, gas plants were allowed to operate until they reached 25 years of age. After 2035, they were retired at the end of their contract, but kept available for reliability. This approach to the life of gas plants was informed by the draft framework for the Clean Electricity Regulation released in 2022.

Adequacy assessments were performed only for 2050, and as a result the scenario only shows capacity and energy results for that year. An operability screen was not performed, but further work will be undertaken.

Demand Forecast

The Pathways scenario, which looks out to 2050, assumes high levels of electrification in the economy. The scenario was created based on theoretical, aggressive, policy-driven electrification in three major sectors: transportation, building heat and industrial process. To develop this scenario, we did not undertake a cost-optimization exercise comparing different decarbonization options on the demand-side. The upcoming work performed by Ontario's Cost-Effective Energy Pathways Study, commissioned by the Ministry of Energy, will provide more insight on the possible evolution of demand in Ontario.

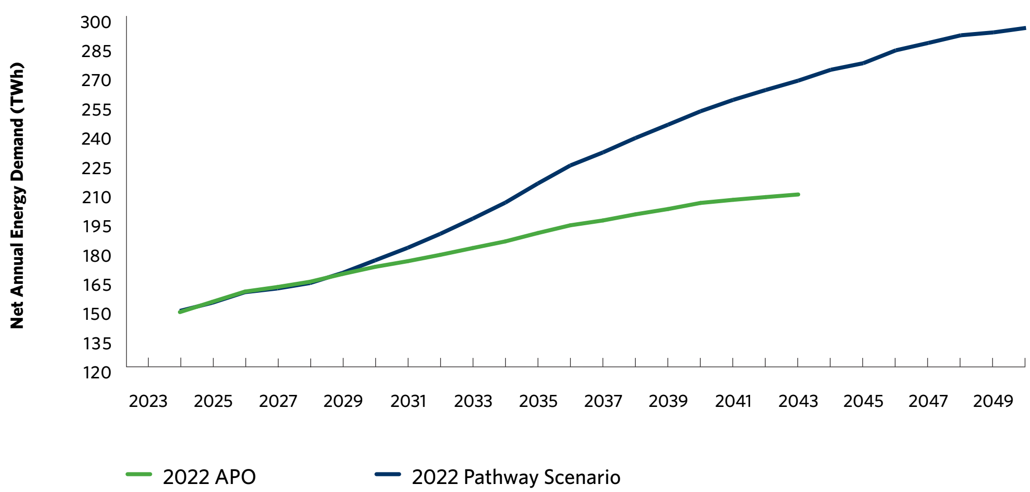
Major scenario assumptions include:

- **Buildings:** A nine-year transition from predominantly fossil-fuelled space and water heating to electric heat pumps, by 2030 for new residential and commercial buildings in Toronto, and by 2035 for the rest of the province. Technological improvement in cold-weather heat pump technology was assumed.
- **Transportation:** Electrification of passenger vehicles aligned with federal regulations; incremental electrification of medium and heavy-duty vehicles, including municipal transit buses, rail transit, and other mobility; and freight vehicles assumed to be fuel cell powered with hydrogen fuel.
- **Industry:** Broad substitution of natural gas fuel to electricity, roughly 20 per cent of current levels by 2050. If the low-carbon hydrogen is manufactured in Ontario, this new industry will represent a significant new load that is not currently included.
- **Conservation:** Assumes savings consistent with the maximum achievable potential from the 2019 IESO Conservation Achievable Potential study.

The demand scenario is based on an assumption of normal weather patterns and does not consider extreme weather events or the projected increase in overall temperature. These changes could have a significant impact on future demand, but are beyond the scope of this project.

As a result of the assumed electrification, the scenario has an average annual growth rate for 2023-2050 of 2.7 per cent for energy reaching an annual energy consumption of approximately 300 TWh by 2050, as shown in Figure 7.

Figure 7 | Energy Demand



Capacity increases by 1.5 per cent per year for summer (Figure 8) and 3.8 per cent for winter, resulting in a winter peak of approximately 60 GW by 2050 (Figure 9).

Figure 8 | Annual Summer Peak Demand

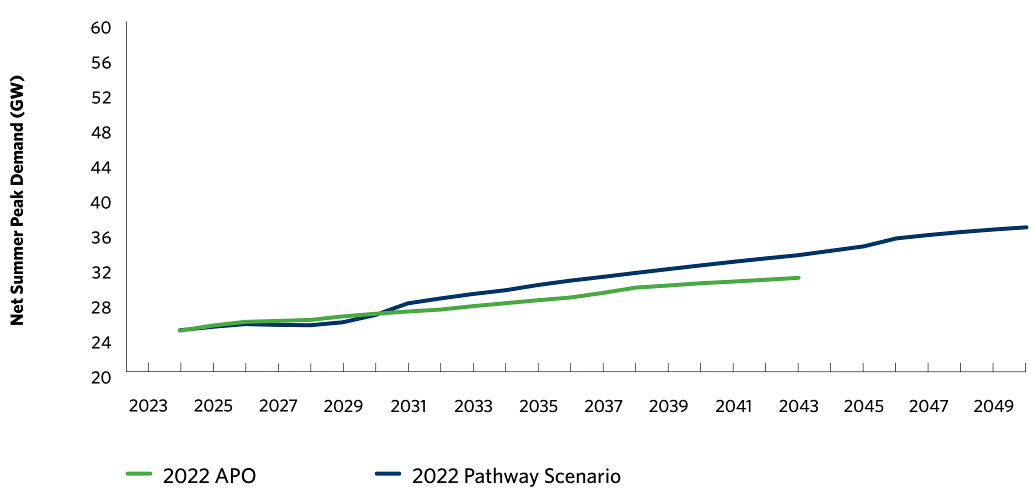
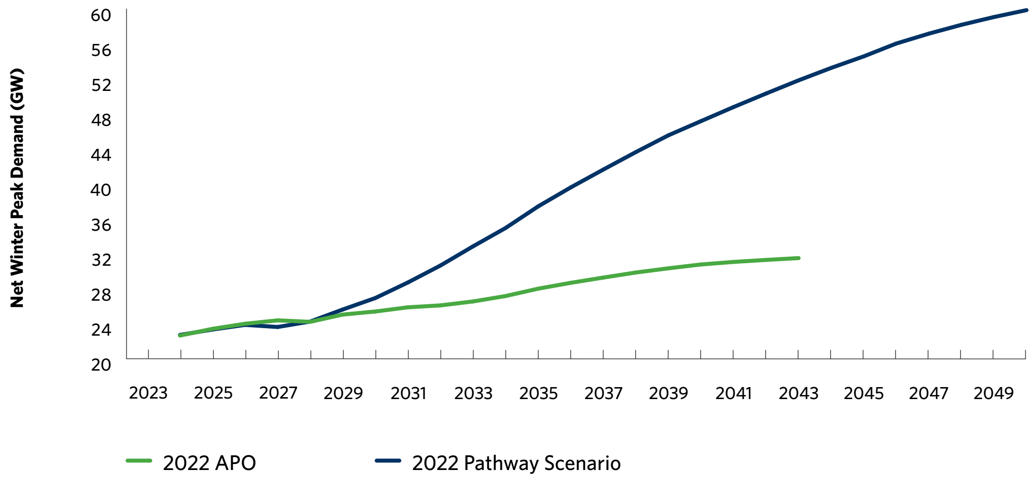


Figure 9 | Annual Winter Peak Demand



The system becomes winter peaking by 2030, largely as result of increased electrification of transportation – i.e., evening or overnight charging – and of heating requirements in buildings. This electrification also changes the shape of system demand during winter, resulting in spring and fall peaks that are higher than summer peaks.

The new profile has up to three ramps per day of 6,000-10,000 MW (see Figure 11), compared with ramps of 2,000-5,000 MW today, attributed to the forecasted new overnight coincident demand from the charging of electric vehicles after business hours and the adoption of electrically powered space heating in the winter season. Managing these ramping requirements would represent a significant operability challenge.

There would likely be an opportunity to manage winter demand through thermal storage and demand response, but there is still considerable uncertainty around the impact on daily demand of future heat pump and electric vehicle requirements. Summer demand profiles do not show significant changes (see Figure 10).

Figure 10 | Summer Daily Load Shape Hourly Profile

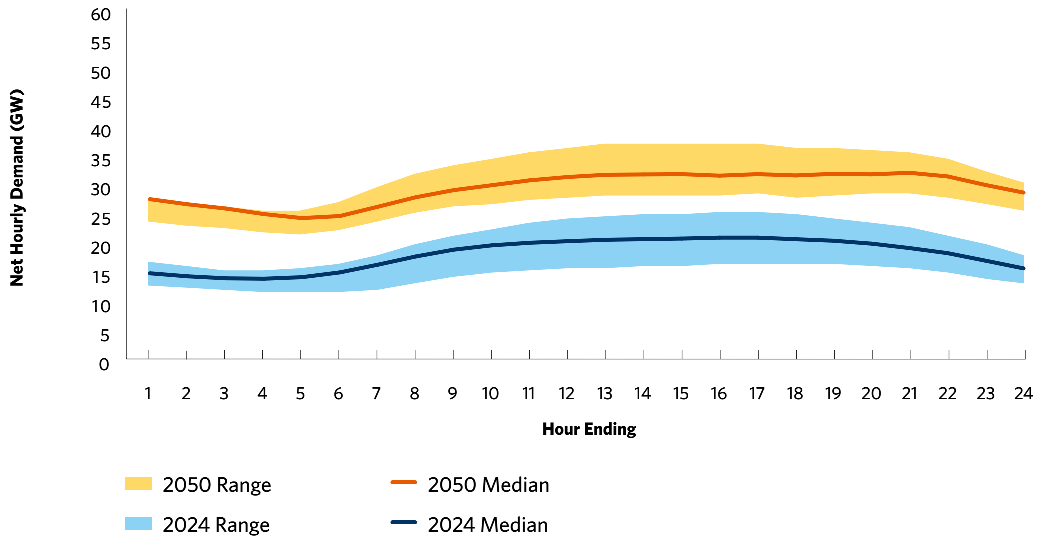
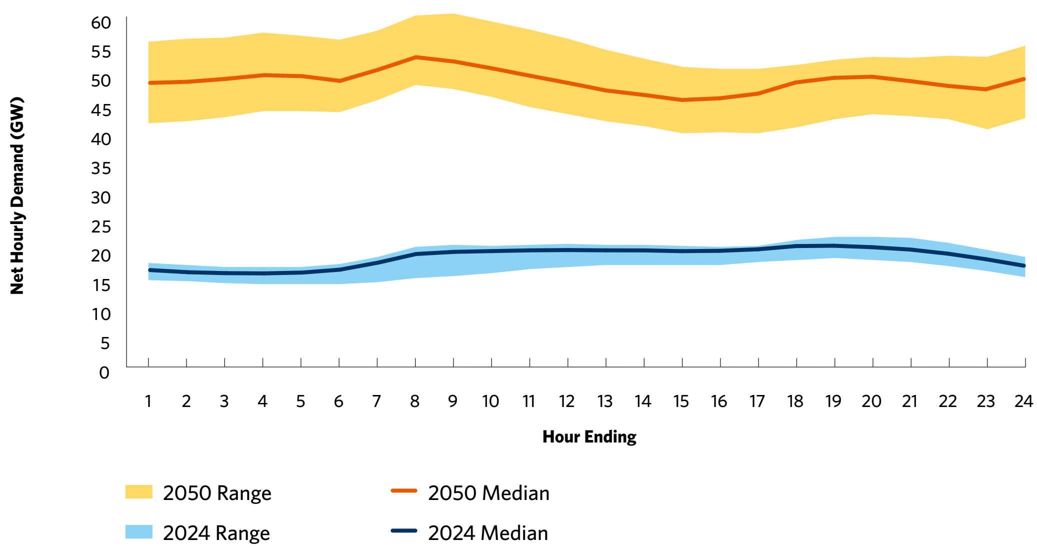


Figure 11 | Winter Daily Load Shape Hourly Profile



As with the Moratorium scenario, this forecast reflects a ramping up of CDM savings, reaching 4,650 MW of demand reduction in 2050[9] at a cost of $11.5 billion over the 2023-2050 period.

[9] These amounts are in line with the maximum potential scenario of the IESO's 2019 Conservation Achievable Potential Study.

Resource Build-out

By 2050, about 20,000 MW of today's supply is still in operation, made up primarily of large nuclear reactors and hydroelectric. Most existing renewable generation is assumed to have reached its end of life, while natural gas is phased out consistent with the zero-emissions goal.

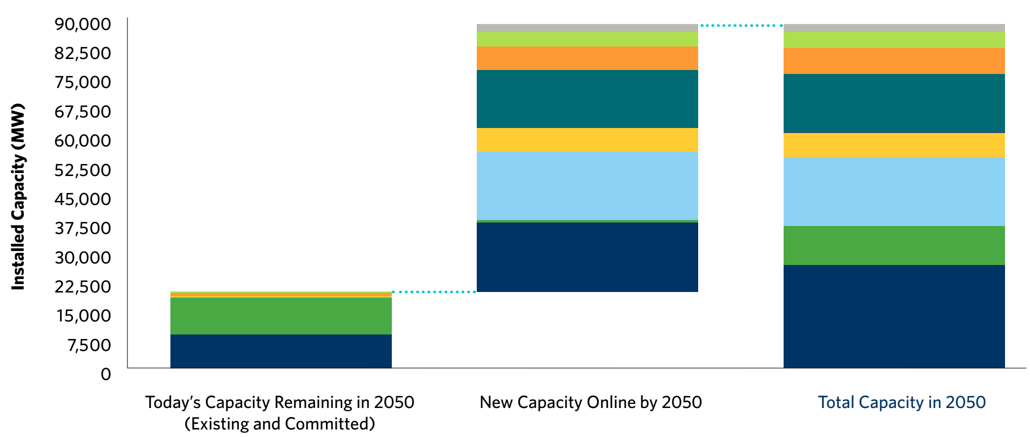
In order to reliably meet the new winter peak demand of 60,000 MW, an additional 69,000 MW of installed capacity is added, in addition to nearly 5,000 MW of CDM that is already included in the demand forecast (see Figure 12).

This scenario includes an additional 17,800 MW of nuclear supply. By 2050, as most of Ontario's existing wind facilities will have reached their end of life, this scenario also includes an additional 17,600 MW of wind and 650 MW of new hydroelectric.

Solar resources provide value during summer peaks in the early years of the scenario. As the system transitions from summer to winter peaks, the value of these resources diminishes and incremental capacity levels off at 6,000 MW in 2036. In addition, as under the Moratorium scenario, the existing 2,500 MW of batteries limited the value of further short-term storage through to 2035. An additional 2,000 MW of long-duration storage is added in the late 2030s to meet adequacy needs.

Assuming its availability in 2036, the analysis suggests that hydrogen becomes a cost-effective[10] resource for reducing peak demand.

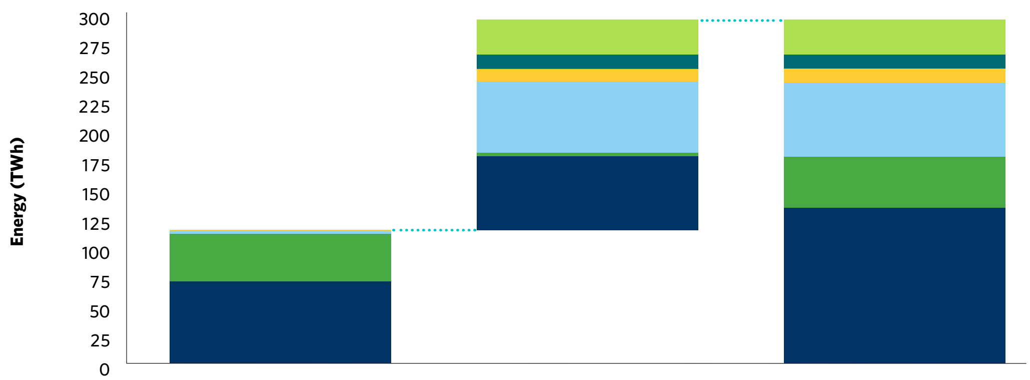
Figure 12 | Pathway Scenario – Installed Capacity in 2050



	Today's Capacity Remaining in 2050 (Existing and Committed)	New Capacity Online by 2050	Total Capacity in 2050
Storage	0	2,000	2,000
Imports	331	3,800	4,131
Demand Response	808	5,936	6,744
Hydrogen	0	15,000	15,000
Bioenergy	41	0	41
Solar	259	6,000	6,259
Wind	160	17,600	17,760
Hydroelectric	9,348	657	10,005
Nuclear	8,653	17,800	26,453
Total MW	**19,600**	**68,793**	**88,393**

[10] Although estimates are based on the most reliable information available at the time of writing, considerable uncertainty remains around cost assumptions for various fuels over the study time period.

Figure 13 | Pathway Scenario – Energy in 2050



	Energy from Today's Capacity Remaining in 2050	Energy from New Capacity Online by 2050	Energy from Total Capacity in 2050
Storage	0	0	0
Imports	0	30	30
Demand Response	0	0	0
Hydrogen	0	12	12
Bioenergy	0	0	0
Solar	1	11	12
Wind	2	62	63
Hydroelectric	41	3	44
Nuclear	70	63	133
Total TWh	**113**	**181**	**294**

Using Ontario's existing interties with Hydro-Québec, as well as incremental new infrastructure in both Ontario and Québec,[11] this scenario includes 4,000 MW of imports. Given Hydro-Québec's current winter capacity constraints, which are outlined above, we assumed that the firm imports would be from new hydroelectric and new wind facilities built in Québec.

By 2050, the total installed capacity reaches about 88,400 MW. In contrast, current installed capacity is about 40,000 MW.

This mix was found to be capacity and energy adequate.

Operability and the future electricity grid

As discussed throughout this report, ensuring reliability is of paramount importance. For a system to be reliable, it must have the flexibility to respond to sudden changes as well as extreme conditions. Future supply mixes will not have some of the traditional resources that currently provide these services, and ensuring reliability without them contains many unknowns. It will require detailed planning studies that incorporate novel approaches, tools and a thorough understanding of the location and technological features of individual resources as they are integrated into the electricity grid. As a result, the IESO has not performed an operability assessment on this scenario. The IESO will work with peers and industry experts over the coming years to address this challenge.

[11] Incremental new infrastructure would include a new intertie between the two provinces and additional reinforcements in Ontario to deliver the capacity to the load centre in the GTA. It would also include necessary reinforcements on the Québec side.

Transmission

The transmission requirements for the Pathways scenario are extensive. In order to achieve a starting point for a system that is capable of incorporating the resources identified and reliably supplying the forecast demand, a significant build-out of Ontario's existing 500 kV network would be required, focusing on paralleling the existing network where possible. Beyond reviewing the impact of different levels of reinforcement to the 500 kV network, the need for an additional 230 kV of bulk reinforcements was also identified to enable the supply mix. (Full details are available in Appendix B, section 2.)

Meeting Forecasted Demand

The challenge of connecting the forecasted demand can be illustrated by considering some high-level assumptions around how many new load supply stations (i.e., transformer stations supplying distribution customers) would be required throughout the province:

- Taking into account existing load supply stations, and assuming that a new station would supply approximately 250 MW of winter load, it would require anywhere from 150 to more than 280 new stations to meet forecasted demand, depending on whether if those stations are fully utilized.
- Costs range between $5 billion and $10 billion based on recent figures for a standard load supply station in a non-urban environment, assuming no work is required on the upstream transmission system and not accounting for downstream distribution costs.
- This would mean that between five and 10 new stations a year, on average, would be needed to meet forecast winter demand in 2050, with a yearly pace potentially outstripping the number of new stations that have been developed across the province in the last decade.

Overall, the cost of building out the bulk 500 kV and 230 kV system to meet the Pathways scenario is estimated to be between $20 billion and $50 billion. This estimate includes new 500 kV and 230 kV network lines and terminations, and new 500/230 kV and 230/115 kV auto-transformation. If 500 kV reinforcement through northwestern Ontario to Manitoba were also needed due to load growth or constraints on resource siting, this could result in an additional $7 billion to $16 billion in costs. The costs for 500 kV lines and terminations are directly informed by the 500 kV reinforcements modelled. The range of cost for 230 kV lines, terminations and for all auto-transformation was informed both by the reinforcements modelled and the unit costs per MW of load growth, assuming typical equipment capabilities.

Many of the needed investments will be challenging to implement given their location within major load centres and populations, which makes land more challenging to acquire, permitting more contested and construction more expensive if undergrounding is necessary. Aside from the bulk reinforcements needed to support growth in the load centres, the Pathways scenario also necessitates major investments in the local distribution system, including step down stations required between the transmission and distribution network, and distribution infrastructure for final connection to the customer. The cost and siting challenge for the required stations and distribution infrastructure will also be substantial.

Pathways: Conclusion and Outcomes

This scenario illustrates the magnitude of the effort required for Ontario to decarbonize its electricity system while responding to economic development and electrification. Focusing on 2050 to align with international targets, this study highlights the goals we are attempting to achieve. It demonstrates an immense build-out of the province's transmission, distribution systems and resources that could more than double Ontario's installed capacity, and that would need every known or potential resource available today. It also requires replacing the necessary services provided by gas, which no resource alone today can do.

We can garner many insights from this scenario, but it is also important to acknowledge its limits. This resource mix was assessed for energy and capacity adequacy in 2050; an operability assessment was not performed. In addition, we did not perform adequacy assessments for the years before 2050. Further planning work is necessary to understand how to manage the transition in a reliable way from now to 2050.

This scenario relies heavily on low-carbon fuels for intermediate, peaking and flexibility needs. Currently there is no like-for-like replacement for the operating characteristics of natural gas. Low-carbon fuels might be able to fill this gap and would be a valuable addition to the supply mix, but they do not yet exist at scale and there are many barriers to commercialization. (See Appendix A, Tab 9.) If low-carbon fuels do not materialize, replacing natural gas will be an even more complex task, requiring more research and analysis into understanding how generation, demand, transmission and storage can be combined to replace gas. It may be possible to overcome all of these barriers, but it will require concerted effort by government and innovators.

In terms of both transmission and supply, the Pathways scenario would need $375 billion to $425 billion in new infrastructure investment, and result in an annual total system cost of approximately $60 billion by 2050. Alternatively, annual system costs can be considered per unit of demand at $200 to $215/MWh, an increase of between 20 per cent and 30 per cent from current unit rates.

Regarding consumer bills, it is difficult to determine a potential rate impact given the changing nature of energy consumption. However, an increased reliance on electricity will significantly increase the volume of consumption on bills compared to today's patterns. (Further information on system costs is available in Appendix A, Tab 8.) However, as noted above, some studies suggest that actual impact on total energy costs could be modest due to offsets and increased efficiency.[12]

[12] Canadian Climate Institute op. cit., p. 26

ONTARIO ENERGY BOARD

FILE NO.: **EB-2021-0002** **Enbridge Gas Inc.**

VOLUME:	**5**	
DATE:	**April 1, 2022**	
BEFORE:	**Michael Janigan**	**Presiding Commissioner**
	Anthony Zlahtic	**Commissioner**
	Patrick Moran	**Commissioner**

EB-2021-0002

ONTARIO ENERGY BOARD

Enbridge Gas Inc.

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

Technical Conference held by videoconference
from 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Friday, April 1, 2022
commencing at 9:35 a.m.

VOLUME 5

BEFORE:

MICHAEL JANIGAN	Presiding Commissioner
ANTHONY ZLAHTIC	Commissioner
PATRICK MORAN	Commissioner

MR. O'LEARY: Sorry about that. Ms. Adams, can you then go back to page 3 of our compendium?

I am not sure if you are familiar with this, but this is a Ministerial directive to the IESO dated September 30th, 2020. And if you scroll down, you will see the words, the legalese:

> "Now therefore the directive attached hereto is approved."

So the government of Ontario has approved the directive to the IESO.

If you could scroll over to the next page, and what this relates to is the government telling the IESO to generate a CDM plan for the years 2021-2024.

And in the -- under the sub heading "Overview of CDM programs", the government of Ontario directs the IESO that the new CDM framework will focus on cost-effectively meeting the needs of Ontario's electricity system, including by focussing on the achievement of provincial peak demand reductions.

Dr. McDiarmid, you understand what peak demand in electricity refers to?

DR. McDIARMID: Yes.

MR. O'LEARY: Okay. And so the government is clearly saying, as I think we all know, that generation capacity at peak is somewhat challenged here in Ontario. And as a result, they want to achieve peak demand reductions and they're directing the IESO to take steps to achieve that objective. Fair enough?

DR. McDIARMID: Yes.

MR. O'LEARY: Okay. And yesterday, in my discussion with Mr. Neme, who is counsel for both ED and GEC, I took him to an Enbridge exhibit that demonstrated that over the past number of years and a couple of years into the future, the forecast is that there will be residential new additions to the gas system of about 42,000 per year.

And we had a little discussion about how, if in a certain area if the new residential customers all went electric and if that required changes to the electricity distribution and transmission infrastructure, he agreed that if those were costs that needed to be incurred to support those new electricity customers, that those costs should be included in the comparison between the all electric system and the hybrid system.

Would that be fair? You would agree with him?

DR. McDIARMID: Sure.

MR. O'LEARY: Okay. And given the time, we didn't go any further, but let me ask you this. So if we had two or three years of natural gas -- what would have been natural gas customers, new residential customers, if they went all electric, so you've got say 120,000 residential customers that are now on the electric system for space heating and hot water, would you agree with me that that is going to have an impact on the peak demand for electricity in Ontario?

DR. McDIARMID: Are we talking summer peak demand or winter peak demand?