ONTARIO ENERGY BOARD

EB-2022-0200

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

Environmental Defence Cross-Examination Compendium For Panel 11 – Capital

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July 30, 2023

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

DECISION AND ORDER

EB-2020-0293

ENBRIDGE GAS INC.

St. Laurent Ottawa North Replacement Project

BEFORE: Anthony Zlahtic
Presiding Commissioner

Emad Elsayed
Commissioner

May 3, 2022

Retrofit Option would allow the pipeline life to be extended by several decades, and the retrofit would also likely be more economical than a full replacement at this time, due to, among other things, the time value of delaying the high capital cost of the replacement. OEB staff noted that this would also provide flexibility for a possible pipeline size reduction if a replacement would be required should demand reductions associated with Energy Evolution or through IRPA initiated by Enbridge Gas be realized. OEB staff suggested that a Retrofit Option may be the most appropriate alternative to address the declining conditions of the St. Laurent Ottawa North Pipeline.

OEB staff submitted that the IRP alternatives pursued by Enbridge Gas, including targeted DSM, in the near term would not feasibly reduce the peak demand served by the St. Laurent system on a scale sufficient to reduce the sizing of the proposed Project.

OEB staff supported the energy planning approach described by the City of Ottawa, and closer collaboration between Enbridge Gas and the City of Ottawa to proactively plan a course of action.

Findings

The OEB finds that Enbridge Gas has not provided sufficient evidence to demonstrate that the proposed Project (pipeline replacement) is the best available alternative. As an example, Enbridge Gas's comparison of the total cost and Net Present Value of the Project (pipeline replacement) versus the pipeline Retrofit Option which would allow for ongoing in-line inspection and repair, showed that the Retrofit Option is a less costly alternative even though Enbridge Gas presented a number of qualitative factors to demonstrate that the replacement option is preferrable.

Several parties argued the Retrofit Option, in addition to having a lower initial capital cost, would also have the potential advantage of providing flexibility for a possible pipeline size reduction should demand reductions be realized. In its reply argument, Enbridge Gas only provided a qualitative description of some of the disadvantages of the Retrofit Option.

The OEB urges Enbridge Gas to thoroughly examine other alternatives such as the development and implementation of an in-line inspection and maintenance program using available modern technology, and propose appropriate action based on its findings, as part of its next rebasing application.

The OEB suggests that Enbridge Gas should work collaboratively with the City of Ottawa and other stakeholders to proactively plan a course of action if and when pipeline replacement is required, including the pursuit of Integrated Resource Planning (IRP) alternatives. Enbridge Gas has not carried out a detailed assessment of the IRP alternative citing that the pipeline integrity concerns must be addressed in less than three years which is the OEB threshold for carrying out an IRP assessment. As discussed earlier, Enbridge Gas has not provided strong evidence to support the claim that the integrity threat to the pipelines is imminent and that replacement in less than three years is necessary.

In more general terms and to the extent applicable for future leave to construct applications, the OEB encourages Enbridge Gas to undertake in-depth quantitative and qualitative analyses of alternatives that specifically include the impacts of IRP, DSM programs and de-carbonization efforts.

3.3 Project Cost and Economics

Enbridge Gas estimated the Project costs as shown in the table below to be approximately $33.9 M for the IP PE pipeline segments and $89.8 M for XHP ST pipelines, totalling approximately $123.7 M.

The abandonment costs are not included in the cost estimates for the Project.

Table 9: Estimated Project Costs

Item No.	Description	IP PE Costs	XHP ST Costs	Total Costs
1.0	Material Costs	$358,484	$1,268,313	$1,626,797
2.0	Labour Costs	$20,369,317	$48,953,572	$69,422,889
3.0	External Permitting & Land	$6,303	787,387	$793,690
4.0	Outside Services	$2,849,096	$4,523,814	$7,372,910
5.0	Direct Overheads	$531,062	$751,515	$1,282,577
6.0	Contingency Costs	$3,318,390	$16,405,401	$19,723,791
7.0	**Project Cost**	**$27,432,652**	**$72,690,002**	**$100,122,654**
8.0	Indirect Overheads	$6,203,171	$16,340,923	$22,544,094
9.0	Interest During Construction	$230,655	$782,119	$1,012,774
10.0	**Total Project Costs****	**$33,866,478**	**$89,813,044**	**$123,679,522**

*XHP ST costs are a Class 5 cost estimate
**Abandonment costs are not included in the cost estimates. Abandonment costs for IP PE are estimated to be $2,817,235 and XHP ST abandonment costs are estimated to be $7,518,548

Enbridge Gas provided the costs of comparable projects completed in the past and approved by the OEB including the cost of the completed Phase 1 and Phase 2 of the St. Laurent Replacement Project. The table below summarizes this information.[39]

Case #	Project Name	City	Year	Pipe Size (Diameter / Material)	Length (km)	Estimated Total Costs (millions)	Estimated $/meter*	Assumed Contingency	Actual Total Costs (millions)	Actual $/meter
EB-2015-0042	Sudbury NPS 10 Replacement Project	Sudbury	2015	NPS 12 Steel	0.7	$2.023	$2,890	10%	$1.023	$1,461
EB-2016-0122	2016 Sudbury Replacement Project	Sudbury	2016	NPS 12 Steel	0.85	$2.188	$2,574	13%	$3.360	$3,953
EB-2016-0222	Sudbury Maley Replacement Project	Sudbury	2016-2017	NPS 12 Steel	2.8	$6.304	$2,251	12%	$4.206	$1,502
EB-2017-0180 (1)	2018 Sudbury Replacement Project	Sudbury	2018	NPS 12 Steel	20	$74.000	$3,700	15%	$82.616	$4,131
EB-2019-0006 (2)	St Laurent Pipeline Project Phases 1/2	Ottawa	2018-2020	NPS 2, NPS 4, NPS 6, & NPS 8 PE	5.1	N/A	N/A	25%	$10.545	$2,077
EB-2019-0172 (3)	Windsor Line Replacement Project	South-western Ontario	2020	NPS 6 Steel	64	$92.744	$1,449	15%	TBD	TBD
EB-2020-0192 (4)	London Lines Replacement Project	South-western Ontario	2021	NPS 4 & NPS 6 Steel	90.5	$133.909	$1,480	14%	TBD	TBD
EB-2020-0293	St Laurent Ottawa North Replacement Project Phases 3/4	Ottawa	2022-2023	NPS 2, NPS 4, & NPS 6 PE NPS 6, NPS 12, & NPS 16 Steel	19.8	$100.123	$5,053	15% for PE 30% for Steel	TBD	TBD

*Variations in cost per metre are significantly influenced by specific project scope parameters.

Notes

(1) EB-2017-0180: The 2018 Sudbury Replacement Project had large proportions of rock excavation, wetland management, a specialized Cathodic Protection design and bypass installations, which are all costly activities that are not present to the same extent or not present at all in the previously approved OEB projects as indicated in the table. It is the influence of this construction scope that has increased the cost per metre for the 2018 Sudbury Replacement Project. Estimated Total Costs for this project were later increased to $83 million.

(2) EB-2019-0006: The actual costs listed are for all components of St. Laurent Phase 1/2. The estimated costs are listed as N/A because portions of Phase 1/2 were not included in the LTC submission EB-2019-0006. The estimated costs included in LTC submission EB-2019-0006 were $5.511 million for the installation of 1.7 km of NPS 6 PE IP main, resulting in a cost/meter of $3241/m.

(3) EB-2019-0172: For comparison purposes, Estimated Total Costs as indicated in the table for the Windsor Line Replacement Project represents "Estimated Incremental Project Capital Costs" (excludes Indirect Overheads of $14.061 million).

(4) EB-2020-0192: For comparison purposes, Estimated Total Costs as indicated in the table for the London Line Replacement Project represents "Estimated Incremental Project Capital Costs" (includes Stations, Services, Abandonment and IDC; excludes Indirect Overheads of $30.189 million).

Enbridge Gas stated that the contingency levels of 15% for polyethylene and 30% steel segments of the Project apply to all direct capital costs. The contingency levels are, according to Enbridge Gas, determined at the time of filing the application "…to correspond to the project/design maturity at the time of filing…". Enbridge Gas indicated that it would reduce contingency cost as the Project's risks are identified and mitigated and design is finalized [40]

The contingency levels for the projects included in the above comparison table are 15% and below except for the St. Laurent Project Phases 1 and 2 where it was 25%. The estimated cost for the Project is the highest in comparison to the costs of other completed projects.

Enbridge Gas has applied for Incremental Capital Module (ICM) Treatment to receive approval for the recovery of the costs for Phase 3 of the St. Laurent Project as part of the Company's 2022 Rates Phase 2 Application.[41] The OEB issued its decision on this

[39] Enbridge Gas Inc. response to I.STAFF.7 a)
[40] Enbridge Gas Inc. response to I.STAFF.8 a-b
[41] EB-2021-0148, Exhibit B, Tab 2, Schedule 1

application and did not approve the ICM treatment for the Phase 3 of the St. Laurent Ottawa North Pipeline project, on the basis that the need for the Project has not been determined at this time.[42]

Positions of the Parties

Regarding the estimated costs of the Project, OEB staff noted that it could not conclude that the estimated costs are unreasonable. OEB staff noted that, should the Project be approved, the OEB's Standard Conditions of Approval, require that Enbridge Gas file with the OEB the actual capital cost of the Project and explain variances and use of contingencies.

No other party made submissions on this issue.

Findings

Given that Enbridge Gas's application is denied based on the lack of evidence to support immediate need, the OEB is not making any specific findings regarding the reasonableness of the estimated Project cost details. However, for similar future applications, the OEB urges Enbridge Gas to provide more details about life-cycle costs including abandonment costs and the probability of future under-utilization. The OEB also encourages Enbridge Gas in future applications to elaborate on the reasons for any significant discrepancies between its cost estimate for the proposed project and other similar projects which was lacking in this application.

3.4 Environmental Impacts

Enbridge Gas retained Dillon Consulting Ltd (Dillon) to complete an Environmental Report: St. Laurent Ottawa North Pipeline Replacement Project (June 2020) (ER), which assessed the existing bio-physical and socio-economic environment in the study area, the alternative routes, proposed the preferred route, conducted public consultation, conducted impacts assessment and proposed mitigation measures to minimize the impacts.

The ER and the consultation process were conducted in accordance with the OEB's *Environmental Guidelines for Location, Construction and Operation of Hydrocarbon Pipelines in Ontario* [7th Edition, 2016] (OEB Environmental Guidelines).

[42] Decision and Order, EB-2021-0148, April 12, 2022, page 12

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2020-0293**	**Enbridge Gas Inc.**
VOLUME:	**Technical Conference**	
DATE:	**March 4, 2022**	

expectation.

MR. ELSON: Yes. I mean, expectation to me means most likely or more than 50 percent. And are you saying that you're 100 percent confident that it is going to be used and useful? I'm not even talking about over its lifetime. I am talking about by 2050.

MR. KEIZER: I don't think anyone in the world can be 100 percent confident about anything right now, Mr. Elson, so I think it is a bit of an unfair question.

MR. ELSON: I mean, Mr. Keizer, that is a fair answer to the question, and if your witnesses wish to provide that, then that's fine. And anticipating that, I will ask: Does Enbridge believe that there is a 90 percent chance -- at least a 90 percent chance that the pipeline will be used and useful by 2050?

MR. KEIZER: I think the answer has been given. They believe it is going to remain used or useful. I don't think that it is fair for them to do a probability scenario on the stand. So I think the answer they have given indeed is their answer.

MR. ELSON: I wasn't asking them to do it on the stand. I asked them to do it in the interrogatory and they didn't provide an answer, and so I am just trying to get some concept of Enbridge's belief about the likelihood that it will be used and useful both in 2050 and in 2077. And the reason that is relevant, Mr. Keizer, is if there's a 50 percent chance -- I am not saying that 50 percent is the right number, but if there is a 50 percent chance that it wouldn't be, then that would clearly affect the project economics.

So I am asking for Enbridge's estimate of the likelihood that the pipeline will remain used and useful as of 2050. Is that closer to 50? Or is that closer to 100 percent?

MR. KEIZER: We're not going to provide that response. I think the response they have given is their position, which is they believe it will be, and we are not giving into possibilities.

MR. ELSON: Mr. Clark, would you agree that if there were to be, say, a 10 percent chance that the pipeline wouldn't be used and useful as of 2050, that would impact the project economics?

MR. KEIZER: I think it is the same point, and the same answer applies.

MR. ELSON: I'm sorry, I don't understand, Mr. Keizer.

MR. KEIZER: It is just simply picking numbers out of the air, Mr. Elson. I think the point is that Enbridge has indicated that they believe that the pipeline is going to be used or useful over its life. And so that is the position. It may be your position to assert something different and that's fine. You are fair to do that. I think they have indicated what their answer is with respect to the life of this pipe.

MR. ELSON: Well, I will ask the question without picking a number out of the air.

Mr. Clark, if you believe that -- or if it were the case that the likelihood of this pipeline remaining used and useful is somewhere under 100 percent, would you agree that that is something that would impact on the project economics?

MR. KEIZER: Sorry, Mr. Elson, it's the same question. I don't think it is a fair question, and I don't -- and we're not providing a response to that question.

MR. ELSON: I will take the refusal and move on.

MR. MILLAR: Mr. Elson, Michael Millar here. We are right about 12:45. Would this be an appropriate time for a break?

MR. ELSON: I see there is an interjection, so I will maybe deal with that first.

MR. MONDROW: Thank you, Mr. Elson. Ian Mondrow for IGUA. Can I ask a follow-up question to the one you just concluded before we break? You are nodding.

So gentlemen and lady, has Enbridge done any analysis of the risk of underutilization of this asset beyond 2050?

MR. CLARK: Brad Clark, Enbridge. In our current forecasting period which does not include 2050 we have not. I am not aware of any analysis past beyond 2050.

MR. MONDROW: Okay. So the answer is no? Is that right? There's been no analysis of the risk of underutilization?

MR. CLARK: None that I am aware of.

MR. MONDROW: Okay, thank you. Thank you, Mr. Elson.

MR. ELSON: Thanks. I am happy to break now.

MR. MILLAR: Thank you. Let's return at 1:30, which

ONTARIO ENERGY BOARD

EB-2020-0293

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. for leave to construct natural gas pipeline and associated facilities in the City of Ottawa

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Submissions of Environmental Defence

St. Laurent Pipeline

March 24, 2022

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have caveats. Tellingly, there are no tables filed anywhere in the evidence showing that the repair option is more expensive than the replacement option. If that could be supported on the facts, that kind of table would clearly have been provided.

Furthermore, Enbridge's estimate of the repair option is likely too high. A large portion of the repair option involves retrofitting the pipes to allow for use of inline inspection tools. However, robotic inline inspection tools do not require this kind of retrofitting. The pre-filed evidence is silent on the use of those tools. They were only discussed after being raised by Mr. Quinn. Even then, the evidence was woefully incomplete. Enbridge acknowledged that it rejected this option after only looking at one potential robotic inspection provider, Pipetel.[15] It also acknowledged Pipetel could have been used on 1.2 km of the pipeline, but that inspection was cancelled on the assumption that a replacement would take place regardless.[16] There was no report to show that robotic inspection could not be done on the remaining portions of the pipeline and no consideration of other providers, despite some seemingly very promising materials put to Enbridge by Mr. Quinn during the technical conference.[17]

The repair option is safe, less expensive, and clearly in the best interests of customers.

Inadequate assessment of options

Possibility of underutilization disregarded

In addition, Enbridge's planning was insufficient because it did not consider the possibility of asset underutilization beyond 2050. In particular, Enbridge did not consider how this risk would impact the weighing of the repair option versus the replace option. Instead, Enbridge implicitly assumed, without any justification, that there is zero risk of underutilization of these assets in relation to decarbonization, even after 2050.

The costs for this project will not be fully depreciated until 2077.[18] By 2050, over $43 million will remain undepreciated.[19] Canada has committed in legislation to net-zero carbon emissions by 2050.[20] It is not certain that this pipeline will be used and useful by that date, let alone utilized to a degree sufficient to continue paying off the remaining cost.

Enbridge was very clear that it did not analyze the risk of underutilization beyond 2050:

> MR. MONDROW: [H]as Enbridge done any analysis of the risk of underutilization of this asset beyond 2050?
>
> MR. CLARK: Brad Clark, Enbridge. In our current forecasting period which does not include 2050 we have not. I am not aware of any analysis past beyond 2050.

[15] Transcript, March 4, 2022, p. 88 lns. 20-28.
[16] Exhibit JT1.6.
[17] Exhibit K1.1
[18] Exhibit I.ED.5.
[19] *Ibid*.
[20] *Canadian Net-Zero Emissions Accountability Act*, S.C. 2021, c. 22.

> MR. MONDROW: Okay. So the answer is no? Is that right? There's been no analysis of the risk of underutilization?
>
> MR. CLARK: None that I am aware of.[21]

Decarbonization is relevant to an analysis of repair alternatives in at least three ways.

First, a repair option can buy time until we have more information on how decarbonization will take place and the extent that it will impact gas demand. This is often described as option value or planning value.

Second, the cost effectiveness of a repair option will improve relative to a replace option as the risk of stranded or underutilized asserts due to decarbonization increases.

Third, decarbonization may in some cases allow for a smaller and less expensive pipeline to be used in the future if replacement is ultimately deemed appropriate.

None of these factors were considered by Enbridge even though its pipeline will not be fully depreciated until the late 2070s.

Ottawa may exit Enbridge's pipeline system

The evidence of the City of Ottawa shows that the risk of underutilization is not so remote that it can be fully ignored. Representatives of the City of Ottawa provided evidence regarding its plans to drastically reduce its carbon emissions.[22] It has detailed plans to reduce its corporate emissions to zero by 2040 and its community-wide emissions to zero by 2050.[23] Its community housing agency, which owns 15,000 homes, plans to reduce its emissions to zero by 2040 though "deep retrofitting and phasing out of natural gas energy equipment."[24]

Although no decisions have been made on this topic, decarbonization may mean that the city no longer relies on Enbridge's distribution system.[25] But even if Ottawa could still use Enbridge's distribution system for renewable gas, it is far from clear that this level of utilization would be sufficient to fund the system.

Feasibility of electrification

Enbridge suggested that electrification is not feasible. This was done in less than a page of text in its reply evidence stating that electricity generation half the size of Pickering Nuclear Generating Station would have to be built to eliminate the St. Laurent pipeline system.[26] This is an incorrect and absurd proposition. Enbridge declined to put forward a witness at the technical conference who could speak to this evidence, despite requests from multiple parties.

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[21] Transcript, March 4, 2022, p. 105.
[22] Evidence of the City of Ottawa, January 17, 2020.
[23] *Ibid.* at p. 4.
[24] *Ibid.* at p. 8.
[25] Sponsor's Interrogatory Responses, 2.1-Staff-2 (b).
[26] Enbridge Responding Evidence, January 27, 2022, p. 5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

EB-2020-0293, Exhibit B, Tab 1, Schedule 1, Page 45

Question:

(a) Please estimate the probability (%) that an NPS 16 pipe will be required in the relevant areas versus an NPS 12 pipe in: (i) 2030, (ii) 2040, and (iii) 2050? Please provide a specific percentage with any caveats as necessary.

(b) Please estimate the probability (%) that any gas pipeline will be required for the area in question by 2050. Please provide a specific percentage with any caveats as necessary.

(c) Is Enbridge willing to bear any of the risk that the proposed infrastructure will be underutilized or stranded by 2050?

Response

a) Because the pipeline(s) are proposed to be replaced for integrity reasons and not demand growth, Enbridge Gas must construct the Project to ensure it can continue to meet its obligation to serve the firm contractual needs of its customers on a design day, based upon existing operational parameters. As a result, based on its OEB-approved demand forecasting methodology and current contractual customer commitments, Enbridge Gas has assumed the need to replace existing facilities as proposed (like-for-like). ED's question seeks to have the Company create new evidence based on hypothetical scenarios that would see demand for natural gas decline significantly from current levels. ED provides no specific basis for its assumptions/scenarios.

It is not practically possible for the Company to completely re-assess the hydraulic models, demand forecasting methodology, engineering design principles, and other factors that currently guide its assessment of projects as part of a response to interrogatories in the current proceeding.

b) Enbridge Gas believes that the pipeline will remain used and useful over its life.

c) These issues exceed the scope of this proceeding and are more appropriately dealt with as part of the Company's 2024 Rebasing proceeding. However, in an effort to be as responsive as possible the Company provides a limited response to ED's question below.

   No, subject to the OEB's approval of the current Updated Application (including the need for the proposed Project), and as the supplier of last resort, the Company is not proposing to bear any incremental risk associated with fulfilling its obligation to serve the firm contractual needs of ratepayers on a design day, while also ensuring the safety and/or reliability of its employees, facilities, and the public.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Preamble:

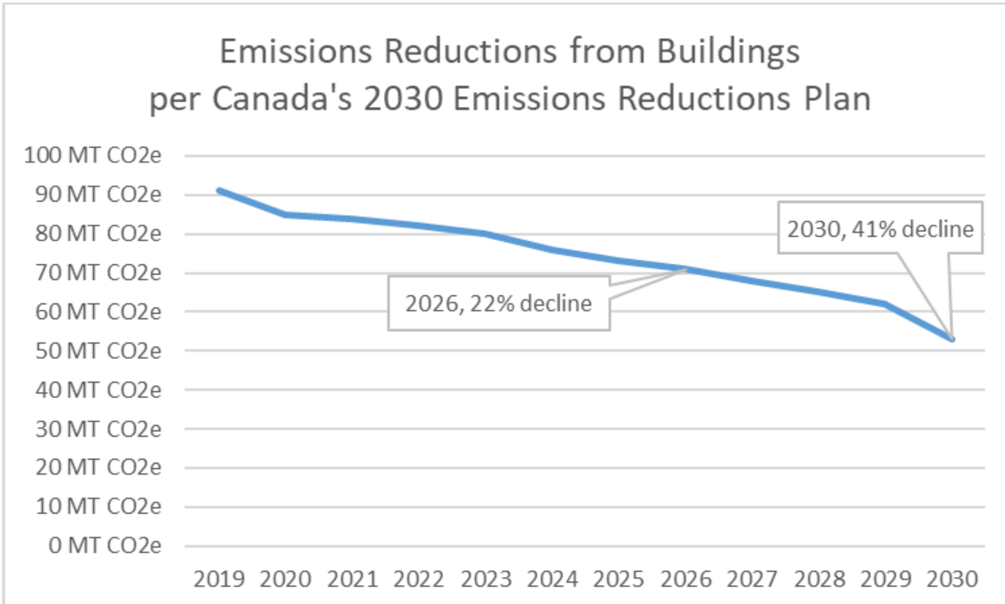
These questions relate to the Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48) at page 55.

Question(s):

a) What is the approximate probability that the incremental pipeline capacity is only needed until (i) 2035, (ii) 2040, and (iii) 2050?

b) Canada's 2030 Emissions Reduction Plan includes targets for carbon emissions from buildings to decline by 22% by 2026 and by 41% by 2030 (illustrated below).[1] This is based on a reduction from 91 CO2e in 2019 to 71 CO2e in 2026 and 53 CO2e in 2030. How might this impact the demand for the incremental capacity from this project before the end of its economic lifetime? Please provide a quantitative answer on a best-efforts basis, stating any necessary caveats and assumptions, and providing a range of possible impacts if appropriate.

[1] Exhibit I.ED.3(a), (f), & (g); see also: *2030 Emissions Reduction Plan – Canada's Next Steps for Clean Air and a Strong Economy* (link); for the full plan see https://publications.gc.ca/collections/collection_2022/eccc/En4-460-2022-eng.pdf.



c) Canada has committed to net-zero emissions from electricity generation by 2035, and re-affirmed its commitment in its 2030 Emissions Reduction Plan.[2] How might this impact the demand for the incremental capacity from this project before the end of its economic lifetime? Please provide a quantitative answer on a best-efforts basis, stating any necessary caveats and assumptions, and providing a range of possible impacts if appropriate.

Response:

a) Enbridge Gas is unable to approximate the probability that the incremental pipeline capacity is only needed until (i) 2035, (ii) 2040, and (iii) 2050. Please see response at Exhibit I.2.6-STAFF-70 part b) for further discussion on this topic.

b) Enbridge Gas is unable to forecast the impact of Canada's 2030 Emissions Reduction Plan on the demand for incremental capacity from this project before the end of its economic lifetime. Please see response at Exhibit I.2.6-STAFF-70 part b) for further discussion on this topic.

c) Please see response at Exhibit I.1.10-STAFF-30 part d).

[2] Exhibit I.ED.3(a), (f), & (g); see also: *2030 Emissions Reduction Plan – Canada's Next Steps for Clean Air and a Strong Economy* (link); for the full plan see https://publications.gc.ca/collections/collection_2022/eccc/En4-460-2022-eng.pdf.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 2, Tab 6, Schedule 2

Question(s):

a) Please provide a table listing the total AMP investments driven by forecast growth in design day or design hour demand for each year from 2023 to 2032. Please also include a breakdown between transmission and distribution projects.

b) What is the probability that a material portion of those investments will be underutilized before the end of their economic life in that the revenue or other benefits underlying the EBO 134 or EBO 188 analysis falls short of the forecasted amount?

c) What is the probability that a significant portion of those investments will be stranded before the end of their economic life in that the incremental capacity is no longer needed because demand declined before that time.

d) Please confirm the net benefits and revenue horizon user in EBO 134 and EBO 188.

e) Please comment on the pros and cons of decreasing the net benefits and revenue horizon underlying the economic analysis set out in EBO 134 and EBO 188 to account for the possibility that the relevant capacity may not required for the full time period.

f) Is this proceeding the appropriate proceeding to consider adjustments to EBO 134 or EBO 188 such as the one described in (e)? Is it within the OEB's jurisdiction to do so? If Enbridge believes this is not the appropriate proceeding to consider these issues, what proceeding should they be considered in?

Response:

a) Please see Attachment 1.

b) Enbridge Gas is unable to approximate the probability that any proportion of these investments will be underutilized before the end of their economic life. Please see response at Exhibit I.2.6-STAFF-70 part b) for further discussion on this topic.

c) Enbridge Gas is unable to approximate the probability that any proportion of these investments will be stranded before the end of their economic life. Please see response at Exhibit I.2.6-STAFF-70 part b) for further discussion on this topic.

d) The customer revenue horizon used in E.B.O 188 evaluations is 40 years except for large volume customers where the maximum is 20 years. E.B.O 134 evaluations are performed over a 40-year horizon.

e) Please see response to part f).

f) Enbridge Gas does not believe it is appropriate to consider adjustments to E.B.O 134 or E.B.O 188 within this Application.

Table 1
2021 Third Party Transportation Cost by Shipper

Line No.	Shipper	Transportation Type (per Exhibit I.4.2-FRPO-101, Attachment 1)	2021 Actual Cost ($ millions)	Whole or part ownership by Enbridge Inc.?
1	TransCanada Pipeline	TCPL Long Haul (line 12) TCPL Short Haul (line13)	348.4	No
2	NEXUS Gas Transmission, LLC	NEXUS	116.2	Yes
3	Vector Pipelines L.P.	Vector	21.3	Yes
4	Panhandle Eastern Pipe Line Company L.P.	U.S. Mid-Continent	22.1	No
5	NOVA Transmission	NOVA	8.4	No
6	Great Lakes Gas Transmission & Great Lakes Pipeline Canada Ltd.	Great Lakes	8.0	No
7	Centra Transmission Holdings Inc.	Centra Pipelines	1.3	No
8	St. Clair Pipelines L.P.	Other Transportation	1.3	Yes
9	2193914 Canada Inc.	Other Transportation	2.5	Yes
10		Total	529.5	

ENBRIDGE GAS INC.

Answer to Interrogatory from Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 4, Tab 5, Schedule 1 (Depreciation)

Question(s):

a) Please provide a table showing the proposed depreciation periods for the five largest asset categories.

Response:

a) Table 1 includes the five largest asset categories, in order of magnitude, based on average plant balances in the 2024 Test Year and the proposed depreciation periods.

Table 1
Service Lives for Major Assets

Account	Description	Estimated Survivor Curve
473.02	Distribution Plant - Services – Plastic	55-S3 (55 years)
475.21	Distribution Plant - Mains – Coated and Wrapped	55-R3 (55 years)
475.30	Distribution Plant - Mains - Plastic	60-R4 (60 years)
465.00	Transmission Plant - Mains	60-R4 (60 years)
478.00	Distribution Plant - Meters	15-S2.5 (15 years)

5.1.10 Growth Capital Expenditure Summary

In the Growth asset class, proposed spending is organized programmatically by sector (residential, commercial and industrial) for the Customer Connections asset subclass. The total average capital spend is forecast to be $295M (EGI) as summarized in **Table 5.1.10-1**. Growth capital is further summarized as part of EGI's total 10-year capital plan in **Section 6**. See **Appendix B – IRP** for the status of the outcomes of the IRP assessment process, including the binary screen and the status evaluation of IRPAs.

Note: The Community Expansion investments are not included in the capital summaries of this AMP. Capital costs related to transmission system reinforcements are included in the expenditure summary for the Transmission Pipe and Underground Storage asset class (see **Section 5.3.6.4**).

Table 5.1.10-1: Growth Capital Summary ($ Millions) - EGI[6]

Asset Class Strategy/Investment Name	Asset Program	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
Customer Additions under EBO 188[7]	Customer Connections	220.4M	249.2M	249.2M	250.3M	260.6M	250.1M	242.8M	246.7M	240.2M	229.6M	**2439.0M**
Hydrogen Strategy	Hydrogen Blending	2.1M	3.8M	5.2M	2.0M	-	-	-	-	-	-	**13.0M**
Enbridge Gas Distribution System Hydrogen Feasibility Study		-	5.1M	5.2M	5.2M	-	-	-	-	-	-	**15.5M**
Distribution System Reinforcement under EBO 188	System Reinforcement	44.5M	41.9M	14.9M	27.1M	8.3M	10.3M	3.4M	10.9M	13.9M	9.2M	**184.5M**
Rideau Reinforcement		-	-	-	-	-	-	-	0.4M	7.5M	63.7M	**71.6M**
Hamilton Industrial Reinforcement		2.5M	10.3M	113.6M	6.5M	-	-	-	-	-	-	**132.9M**
East Kingston Creekford Road Reinforcement		4.6M	24.1M	-	-	-	-	-	-	-	-	**28.7M**
North Parry Sound Seguin Trail Reinforcement		-	-	-	-	-	-	-	-	-	23.8M	**23.8M**
Southeast Owen Sound County Rd 40 Reinforcement		-	-	34.1M	-	-	-	-	-	-	-	**34.1M**

[6] Includes overhead allocation
[7] The 10-Year Forecast for Customer Connections was informed by the 2022 LRP

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
736975	2023	10

Investment Name

Enbridge Gas Distribution System Hydrogen Feasibility Study

Investment Description

Risk/Concern/Opportunity:
Comprehensive techno-economic feasibility study of blending hydrogen into Enbridge Gas Inc.'s (EGI) existing natural gas distribution and transmission network across Ontario.

Assets: Hydrogen Study

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Evaluate the technical feasibility and maximum limits of blended hydrogen gas in existing networks, identify necessary retrofits or upgrades for varying concentrations of hydrogen, and develop a staged roadmap for transitioning Ontario's gas network to a low-carbon future in line with technical and economic barriers and opportunities. The assessment comprises the entirety of EGI's gas pipeline network in Ontario:
- 78 214 km of gas distribution main lines
- 66 787 km of gas distribution service lines
- 5 471 km of gas transmission lines

Resources: 3rd party contractor

Solution Impact: By blending hydrogen at strategic locations across EGI's existing gas network, EGI aims to reduce the carbon intensity of its 3.8 million residential, commercial, institutional and industrial customers across over 500 communities in Ontario.

Project Timing & Execution Risks:
Study to be completed in 2026

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - Hydrogen Blending
Investment Stage	Initial		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	30 - Richmond Hill
	Asset Program (EGI)	GTH - Hydrogen Blending
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
Enbridge Gas Distribution System Hydrogen Feasibility Study	$ 12,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 4,000,000	$ 4,000,000	$ 4,000,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

Table 5: 2024 Investments Subject to LTC

Asset Class	Investment Code	Investment Name	2024 Forecast	2023 to 2032 Forecast	
Distribution Pipe	10288	St. Laurent Phase 4 - Lower Section (Plastic)	$512,223	$10,165,462	/u
Distribution Pipe	10293	St. Laurent Phase 3 - North/South (NPS12/16 Steel)	$12,165,299	$121,804,143	/u
Distribution Pipe	10294	St. Laurent Phase 4 - East/West (NPS12 Steel)	$51,230,980	$53,906,876	/u
Distribution Pipe	10292	St. Laurent Phase 3 - Montreal to Rockcliffe (Plastic)	$192,084	$4,228,711	/u
Distribution Pipe	10290	St. Laurent Phase 3 - Coventry/Cummings/St. Laurent (Plastic)	$23,376,683	$25,033,190	/u
Growth	736974	Hydrogen Blending Phase 2	$1,920,837	$9,026,516	/u
Growth	102119	Brockville Gate Extension	$327,083	$3,131,604	/u
Growth	30500	NW 2103 Dundalk XHP Reinforcement SRP	$6,525,723	$7,226,628	/u
Growth	734979	Grimsby-Lincoln Expansion Project - Natural Gas Expansion Program (NGEP)	$1,677,531	$9,115,779	/u
Growth	739185	HAMI: Caledonia North Reinforcement, Haldimand	$1,540,854	$2,056,505	/u
Growth	30563	SRP_Southwest_Bluewater_New STN & Reinforcement_NPS4_7200m_3450kPa	$884,097	$8,656,067	/u
Growth	736259	Hamilton Reinforcement Project	$11,516,242	$125,821,854	/u
Growth	30542	SRP_Southeast_Owen Sound_County Rd 40_Reinforcement_NPS12_11800m_4670kPa	$2,667,446	$33,636,531	/u
Compression Stations	100901	Dawn to Corunna	$13,845,083	$200,337,430	/u

Compression Stations	48732	Waubuno Compression Lifecycle	$2,355,233	$29,218,620	/u
Transmission Pipe & Underground Storage	49758	Panhandle Regional Expansion Project	$194,881,628	$224,328,497	/u
Transmission Pipe & Underground Storage	740055	Panhandle Regional Expansion Project - Dawn Facilities	$5,382,040	$92,044,573	/u
Transmission Pipe & Underground Storage	736923	Panhandle Regional Expansion Project - Leamington Interconnect	$217,399	$118,751,452	/u
Transmission Pipe & Underground Storage	48654	Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)	$1,262,995	$251,357,572	/u
Transmission Pipe & Underground Storage	503069	Dow A McPlank Connection	$959,425	$2,947,237	/u

94. For investments greater than $10 million that are subject to an LTC in the 10-year AMP, please see Exhibit 2, Tab 6, Schedule 2, Appendix A.

7.2 Projects/Programs Not Subject to Leave to Construct

95. Construction projects may not require leave from the OEB prior to construction in the following circumstances:
   a) The project does not meet the leave to construct criteria prescribed in the *OEB Act*;
   b) The project falls under federal jurisdiction that requires approval from the Canada Energy Regulator; or,
   c) The project involves relocation or reconstruction of an existing pipeline unless the size of the line is changed or additional land is required.

96. Table 6 lists the investments that have been identified in 2024 as not subject to LTC, overhead allocations are included in the forecast costs.

Table 6
2024 Investments Not Subject to LTC

Asset Class	Investment Code	Investment Name	2024 Forecast	2023 to 2032 Forecast	
Distribution Pipe	4160	Vintage Steel: NPS 12 SC HP on Parliament St, Carlton St to Front St	$2,826,373	$2,826,373	/u
Distribution Pipe	734020	NPS 8 Onion Lake Lateral Replacement	$3,700,069	$4,356,235	/u
Distribution Pipe	48846	SARN - Errol Rd E Leakage - Sarnia BU	$2,167,797	$2,167,797	/u
Distribution Pipe	48831	SARN-Point Edward LP Leakage - Sarnia BU	$2,032,570	$2,072,201	/u
Distribution Pipe	49816	WIND: Mersea Rd 2 - Ph 2, Leamington, Replacement	$2,210,241	$2,210,241	/u
Distribution Stations	735335	GTAW Parkway Gate Station Rebuild Phase 2	$9,365,335	$11,312,293	/u
Distribution Stations	7777	WINSTON CHURCHILL AND STEELES FEEDER	$7,043,068	$9,659,604	/u
Distribution Stations	502429	WIND-03D-301 Leamington North Gate Station	$5,011,302	$8,646,696	/u
Distribution Stations	734689	LOND: 14R-104 Beachville Domtar Trans Stn	$5,051,981	$5,696,544	/u
Distribution Stations	101359	WIND 05A-201 Turkey Creek	$2,604,524	$2,849,458	/u
Distribution Stations	100920	TIMM: Hearst TBS, Rebuild	$3,784,550	$3,955,332	/u

Table 6
2024 Investments Not Subject to LTC

Asset Class	Investment Code	Investment Name	2024 Forecast	2023 to 2032 Forecast	
Growth	736975	Enbridge Gas Distribution System Hydrogen Feasibility Study	$5,762,510	$15,422,809	/u
Growth	500705	NW 5301 Barrie - Collingwood Pressure Increase SRP	$2,440,993	$3,738,965	/u
Growth	30556	SRP_Southwest_London_13O-402STN_Westmount Station Rebuild	$4,294,183	$4,552,009	/u
Growth	739267	HAMI: Caledonia Transmission Station Rebuild (15X-401)	$9,219,864	$9,993,340	/u
Growth	734672	SRP_Southwest_Kerwood_12K-301STN_Rebuild	$6,504,425	$6,697,794	/u
Growth	49805	SRP_Southwest_Hensall Trans_14N-302STN_Rebuild	$5,910,707	$8,488,963	/u
Compression Stations	740281	Hagar 412FKR357 Major Overhaul and Foundation Work	$7,577,971	$7,577,971	/u
Transmission Pipe & Underground Storage	738426	LSEC: Meter Station Filter	$2,248,654	$2,367,094	/u
Transmission Pipe & Underground Storage	6377	PCRW:Wells-Upgrade	$7,747,375	$11,443,473	/u

Table 6
2024 Investments Not Subject to LTC

Asset Class	Investment Code	Investment Name	2024 Forecast	2023 to 2032 Forecast	
Transmission Pipe & Underground Storage	1787	Panhandle NPS 16 - South of S Service Rd Class Location Replacement	$2,551,111	$2,680,024	/u
Real Estate & Workplace Services	100492	Dryden Operations Centre	$3,157,488	$8,958,563	/u
Real Estate & Workplace Services	501930	Dawn EOC MCR - COVID Impacts	$4,388,908	$5,033,472	/u
Real Estate & Workplace Services	737374	Ottawa - New Building	$13,317,801	$35,383,329	/u
Real Estate & Workplace Services	3640	Station B New Building	$25,611,157	$38,590,879	/u
Real Estate & Workplace Services	737786	Brockville Operations Centre - New Build	$4,481,952	$10,712,219	/u
TIS	102304	Enterprise Contact Center	$2,392,105	$2,983,095	/u
TIS	736081	General Service Rebasing Changes	$15,366,694	$17,914,329	/u
TIS	736942	Contract Market Systems - Technology Obsolescence	$22,832,346	$69,786,961	/u
TIS	736066	Utility Weather & Demand Harmonization - Rebasing	$5,122,231	$5,122,231	/u
TIS	739859	5 week Planning Tool	$5,122,231	$6,396,468	/u
TIS	102291	Contract Market Harmonization	$6,402,789	$19,195,783	/u
TIS	737248	AWS Ph3 2024	$2,112,920	$2,112,920	/u

Table 6
2024 Investments Not Subject to LTC

Asset Class	Investment Code	Investment Name	2024 Forecast	2023 to 2032 Forecast	
TIS	102115	eGIS / GPS Hardware lifecycle 2024	$2,176,948	$2,176,948	/u

7.3 Customer Additions and Profitability Index Values

Customer Connections Feasibility

97. Enbridge Gas expands its distribution system in accordance with the OEB's guidelines for the expansion of natural gas service. These guidelines are articulated in the E.B.O 188 report.[27] The intent of E.B.O 188 is to facilitate rational expansion of natural gas service while protecting existing customers from undue cross-subsidization.

98. For the general service market, Enbridge Gas uses a portfolio approach (i.e., Investment Portfolio and Rolling Project Portfolio) to manage distribution system expansion activities and ensure that required profitability standards are achieved at both the individual project and the portfolio level.

99. If the expansion is driven by large commercial/industrial customers (contract market), the feasibility analysis factors in the incremental cost and revenue of the customers on the project and determines whether the customers would be required to pay a Contribution in Aid of Construction (CIAC). This is explained in more detail in the Feasibility Process below.

[27] E.B.O 188 Final Report of the Board, January 30, 1998.

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

DECISION AND ORDER

EB-2019-0294

ENBRIDGE GAS INC.

Application for leave to construct natural gas pipelines and associated facilities in the City of Markham, Regional Municipality of York

BEFORE: **Susan Frank**
Presiding Commissioner

Lynne Anderson
Chief Commissioner

Emad Elsayed
Commissioner

October 29, 2020

premature to limit potential uses for hydrogen and stifle potential innovation by failing to even study small-scale practical applications such as the Project.

Enbridge Gas submitted that a combination of solutions will be needed as part of the transition to a low carbon economy. These solutions include energy efficiency via Demand Side Management (DSM), renewable hydrogen, renewable natural gas from bio sources, electrification, geothermal, the use of gas fired heat pumps, and high efficiency furnaces, amongst others. Enbridge Gas submitted that hydrogen blending can be part of its suite of activities to assist customers in reducing GHG emissions. H2GO agreed that a plurality of carbon mitigation responses is required in order for Canada to meet its GHG reduction commitments.

SEC submitted that the OEB should not try to ascertain if the future of the natural gas system involves blended gas, but instead should view the Project as a pilot project with the goal to learn enough to help assess later what role hydrogen can play, if any. Pollution Probe agreed with SEC and submitted that approval of the Project should not be construed as hydrogen blending being a better or cleaner energy solution than alternatives, but rather as a proof of concept to better understand if hydrogen blending should be considered for the future and to what extent. OEB staff submitted that, while there may be more cost effective alternatives to hydrogen blending for reducing GHG emissions, it would be premature to rule out hydrogen blending as a means to reduce GHG emissions before it is better understood in the Ontario context.

Findings

The OEB finds that Enbridge Gas has satisfied the evidentiary burden of proof in the value of proceeding with this Project as a first phase pilot. The proposed Project is a limited scope opportunity to determine if hydrogen blending should be pursued at a larger scale. The OEB supports innovation and recognizes that some initiatives might not produce the desired results but accepts that this Project will increase the learning on hydrogen fuel blending, and it should proceed.

There was general agreement by intervenors that hydrogen is an expensive fuel source compared to natural gas, could be dangerous at high concentration levels (see next section), and cannot make a significant reduction to the carbon emission levels in gas delivery. VECC noted that “there are no compelling reasons of energy efficiency, security of supply or safety to blend hydrogen into the natural gas distribution system.” SEC commented that “hydrogen is fundamentally an energy storage medium” and will never replace natural gas. OEB staff noted that the OEB’s Marginal Abatement Cost

Curve[1] did not include the cost of hydrogen as an abatement option – noting that it was more expensive than other abatement options such as energy efficiency and Renewable Natural Gas (RNG).

However, there was also general acknowledgement by the parties that the reduction in carbon emissions targeted by the Provincial Government cannot be achieved without exploring a variety of approaches to achieve such reduction. Enbridge Gas has proposed a pilot to inject a controlled quantity of hydrogen into its natural gas system for a small number of customers. This Project is expected to provide detailed information on the impact of hydrogen blending on the level of carbon reduction, the risk to the distribution system and customers' equipment, the potential for the expansion of hydrogen blending into other areas of its distribution system, and details on the hydrogen gasification process. The OEB agrees that despite the apparent limited potential of hydrogen blending, the learning from the proposed Project would be beneficial and the Project should proceed.

3.2 Safety and Technical Risks

Enbridge Gas's preliminary assessment of hydrogen blending involved literature reviews, industry consultation, field surveys of Enbridge Gas's system, onsite surveys of residential and commercial customer equipment, analytical modeling, and risk assessments. Enbridge Gas stated that this work identified several technical constraints and unknowns that are mainly related to the impact of hydrogen on existing gas distribution infrastructure and customer-owned appliances. Enbridge Gas stated that the work also helped identify a suitable level of hydrogen that may be injected into the natural gas distribution system and where that injection could occur in an existing Enbridge Gas network. Although there are examples of projects in other jurisdictions with hydrogen concentrations up to 20% by volume, Enbridge Gas decided that a concentration of up to 2% hydrogen is safe and reliable for the Project.

The TSSA filed evidence in this proceeding and answered interrogatories on that evidence. The TSSA has reviewed the design of the Proposed Facilities and the safety risk information provided to it by Enbridge Gas. The TSSA has indicated its general support for the Project.

FRPO submitted that, while the TSSA filed evidence and answered interrogatories, the evidence demonstrates a strong reliance on industry knowledge, literature review and

[1] EB-2016-0359, Marginal Abatement Cost Curve, July 20, 2017, https://www.oeb.ca/sites/default/files/OEB_MACC%20Report_20170720.pdf

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

EB-2022-0157

Enbridge Gas Inc.

Application for leave to construct natural gas pipeline and associated facilities in the Municipality of Chatham Kent, Municipality of Lakeshore, Town of Kingsville and Municipality of Leamington

PROCEDURAL ORDER NO. 4
December 14, 2022

Enbridge Gas Inc. (Enbridge) applied to the Ontario Energy Board (OEB) on June 10, 2022, under sections 90 and 97 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), for an order granting leave to construct approximately 19 kilometres of natural gas pipeline from its Dover Transmission Station in the Municipality of Chatham Kent to its existing pipeline in the Municipality of Lakeshore, and approximately 12 kilometres of natural gas pipeline in the Municipality of Lakeshore, Town of Kingsville and the Municipality of Leamington (Project). The Project also involves valve site station work required to tie in the proposed pipelines. Enbridge has also applied to the OEB for approval of the form of land-use agreements it offers to landowners for the routing and construction of the Project.

Proceeding to Date

The OEB issued the Notice of Hearing on July 4, 2022, and Procedural Order No. 1 on August 12, 2022. Procedural Order No. 1 set the schedule for written discovery by interrogatories and for a transcribed technical conference.

On October 6, 2022 and October 7, 2022, the OEB held a two-day transcribed technical conference. Procedural Order No. 1 set October 14, 2022 for written responses to undertakings from the technical conference.

On October 12, 2022, Enbridge requested an extension to file its written responses to undertakings to October 19, 2022. To accommodate Enbridge's extension request, the OEB issued Procedural Order No. 2 on October 14, 2022. Procedural Order No. 2 set the schedule for the remainder of the written hearing including: granting the extension to Enbridge to file undertaking responses, filing of intervenor evidence and Enbridge's reply evidence, written discovery on intervenor and Enbridge's reply evidence, filing of the argument-in-chief, filing of OEB staff and intervenor written submissions and filing of Enbridge's reply submission.

The OEB approves Enbridge's request to place the application in abeyance. The application will be held in abeyance until such time as the OEB receives updated information from Enbridge, and the OEB issues a new procedural schedule. The OEB will assess the updated application and determine what procedural steps are appropriate.

Regarding the issues raised by IGUA, FRPO and Environmental Defence, the OEB is of the view that the economics of the project, the applicability of EBO 134 and EBO 188, and the extent to which contributions in aid of construction should be required are issues that are in scope for this proceeding. Enbridge may wish to consider whether to provide additional evidence on those issues as part of its proposed update to its application. Enbridge may also wish to consider whether it should be communicating with potentially affected customers regarding the position of some parties that contributions in aid of construction should be required.

Enbridge has indicated that it expects to file no later than mid-February 2023. The OEB expects Enbridge to confirm by February 1, 2023 the date by which it will file its amended application.

It is necessary to make provision for the following matters related to this proceeding. Further procedural orders may be issued by the OEB.

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Enbridge's application is in abeyance as of December 5, 2022. The application will remain in abeyance until Enbridge files the amended application and the OEB issues a new procedural schedule. The amended application must comply with the filing requirements set in the *OEB Natural Gas Facilities Handbook* and *OEB Rules of Practice and Procedure* and should include updated exhibits and responses to interrogatories and undertakings where those are materially affected by the amended application.

2. No later than February 1, 2023 Enbridge shall confirm the date it expects to file its amended application.

Parties are responsible for ensuring that any documents they file with the OEB, such as applicant and intervenor evidence, interrogatories and responses to interrogatories or any other type of document, **do not include personal information** (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

C. Updated Panhandle System Capacity

19. Following the Application being placed into abeyance in December 2022 (at the Company's request), Enbridge Gas re-evaluated existing system capacity based on the impact of actual 2022 customer demands, updated forecast demands, updated SWAHV, and supply volumes on the Panhandle System.[2] As a result of this assessment the Company found that:

    i. The nature, magnitude and location of actual customer demands has changed and the Company expects there to be less pressure loss on the existing system, and thus greater existing/remaining capacity, than originally estimated. The existing Panhandle System is now forecasted to be able to serve an additional 27 TJ/d of capacity compared to the previous modelling and forecasts, until Winter 2024/2025 at which time customer demands are expected to exceed the system's capacity.
    ii. Panhandle System capacity decreased by 3 TJ/d due to the updated SWAHV.
    iii. There were no changes to system capacity due to supply volumes and their locations.

20. The outcome of the changes described above increased the existing Panhandle System capacity by 24 TJ/d from 713 TJ/d to 737 TJ/d. The impact to the Project's in-service date due to this increase in Panhandle System capacity combined with the decrease in customer demand (described in Section B above) is described in Section E below.

D. Contributions in Aid of Construction

21. Following the OEB's remarks in Procedural Order No. 4 regarding CIAC, Enbridge Gas account managers conducted outreach to customers who indicated their intention to submit an EOI bid. Customers were asked about the impact a requirement for CIAC would have on their demands for new/incremental service. The themes of the feedback are as follows:

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[2] Existing system capacity is based on the existing pipeline facilities, customer demand volumes and location, the energy content of natural gas (also known as the system-wide average heating value, or "SWAHV"), and supply volumes and location.

- Customers submitting EOI bids for new/incremental service were generally doing so under the assumption that the OEB would apply the established regulatory framework for transmission system expansion projects, which does not require CIAC, consistent with similar projects constructed in the past. Customers generally indicated opposition to being required to provide CIAC to support transmission system expansion in this instance.
- No customer indicated that they would be willing to provide CIAC for a transmission system expansion project without understanding the magnitude of the CIAC and the unique justification for its selective application in this instance.

22. On this basis, and for the reasons already set out on the record for the current Application, the Company re-iterates that it is not appropriate to require CIAC from specific customers for the proposed Project because, as a transmission system, the Panhandle System transports natural gas for the benefit of all customers within the Panhandle Market – rather than individual or specific customers.[3]

23. The Panhandle System transports natural gas supply and stored volumes from the Dawn Hub and upstream supply basins into and through Enbridge Gas's integrated storage and transmission systems, and ultimately distribution systems to end use customers. Enbridge Gas's transmission systems are connected to multiple upstream supply basins, storage facilities and markets through ex-franchise transmission pipelines. This provides Enbridge Gas's ratepayers access to multiple sources of economic natural gas supply. As a result, Ontario ratepayers pay a lower cost for natural gas supply than they otherwise would and rarely experience disruption of firm natural gas services. Accordingly, the continued expansion of the Panhandle System will allow existing and future customers to experience the same diversity, reliability, and resiliency of Enbridge Gas's integrated natural gas storage and transmission systems. This results in increased energy price stability and competitiveness, and mitigates supply shortfall or disruption to the benefit of all Ontario natural gas customers.

E. Outcome and Summary

24. The combined effects of the decrease to the customer demand forecast (as described in Section B above) and an increase in the existing system capacity (as

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[3] Exhibit JT1.3

8. Stage 3 analysis considers other quantifiable benefits and costs related to the construction of the Project, not included in the Stage 2 analysis, and other non-quantifiable public interest considerations.

i. Stage 1 – Project Specific Discounted Cash Flow Analysis /U

9. The Stage 1 DCF analysis for the Project can be found at Exhibit E, Tab 1, Schedule 5. This schedule indicates that the Project has a NPV of negative $150 million and a PI of 0.48.

10. A summary of the key input parameters, values and assumptions used in the Stage 1 DCF analysis can be found at Exhibit E, Tab 1, Schedule 3.

11. Incremental cash inflows are estimated based on the transmission portion ("transmission margin") of 2023 OEB-approved rates.[2] The revenue calculation for the transmission margin can be found at Exhibit E, Tab 1, Schedule 4. /U

12. Incremental cash outflows, in accordance with E.B.O. 134, include all estimated incremental Project costs. Indirect overhead is not included within cash outflows.

13. The total estimated incremental cost of $289.2 million can be found at Exhibit E,Tab 1, Schedule 2, Line 7.

ii. Stage 2 – Benefit/Cost Analysis

14. A Stage 2 analysis was undertaken as the Stage 1 NPV is less than zero (negative $150 million). The Stage 2 analysis considers the estimated energy cost savings that accrue directly to Enbridge Gas in-franchise customers as a result of using natural /U

[2] EB-2022-0133

gas instead of another fuel to meet their energy requirements. The difference in fuel cost is derived as:

[Weighted Average Alternative Fuel Cost - Cost of Natural Gas] × Energy Use

15. The Stage 2 NPV of energy cost savings are estimated to be in the range of approximately $226 million over a period of 20 years to $353 million over 40 years. A range is provided as the outcome can vary depending upon the assumptions for alternative fuel mix, energy use, fuel prices, and term. /U

16. The Stage 2 energy cost savings have only been calculated for the general service customer class. It is assumed that contract rate customers will not choose an alternative fuel if natural gas is not available to them. The non-availability of natural gas will cause contract rate customers to expand or move their operations to other jurisdictions, likely outside of Ontario, where their natural gas needs can be served. The resulting impacts to the Ontario economy are addressed in Stage 3.

17. The results and assumptions associated with this analysis can be found at Exhibit E, Tab 1, Schedule 6.

iii. Stage 3 – Other Public Interest Considerations

18. There are several other public interest factors for consideration as a result of the Project. Some are quantifiable and others are not readily quantifiable. Quantifiable factors include GDP, taxes, and employment impacts. Applicable other public interest factors are discussed below:

/U

<u>Economic Benefits for Ontario</u>

19. The construction of the Project will provide direct and indirect economic benefits to

Stage 2 (Customer Fuel Savings) Data for Panhandle Regional Expansion Project

Assumptions

(a)	(b)	(c)	(d)=(b)-(c)
Fuel Prices	$/m^3	Gas $/m^3	Diff $/m^3
Heating Oil	1.90	0.30	1.60
Propane	1.14	0.30	0.84
Electricity	1.08	0.30	0.78

Fuel Mix in the Event Gas is Not Available

	(e)	(f)=(d)*(e)
	General Service	
	Fuel Mix	Wt Ave Diff $/ M^3
Heating Oil	24%	0.382
Propane	10%	0.080
Electricity	67%	0.520
Total %	100%	
Weighted Savings $/m^3		0.982

Gas and alternative fuel prices are the average posted prices for the 12 month period ending March 2023

Prices in the above table are before the added cost of Carbon.

Carbon Prices The cost of carbon is added to the price of each fuel in above table

	2024	2025	2026	2027	2028	2029	2030
Cost per tonne	$80	$95	$110	$125	$140	$155	$170

	Future Yrs 2031 and beyond
Cost per tonne	$0

Calculation for Stage 2 Incremental Energy Demand

	Estimated Energy Demand with Pipeline Built
Equals	Potential annual energy demand (for Stage 2 calculations)
Times	Weighted Average Savings per M3
Equals	Annual Fuel Savings: Natural Gas Vs Alt Fuels

Discount Rate for Net Present Values 4.0%

Length of Term for Fuel Savings

Stage 2 estimated based on 20 years and 40 years

Present Value of Customer Fuel Savings

For conservatism, the NPV is assessed over 20 years with sensitivity at 40 years

Figures in $ Millions	20 Years	40 Years
General Service Fuel Savings	226	353

NPV Fuel Savings Range from $226 Mil over 20 yrs to $353 Mil over 40 yrs

Table 2: Panhandle System Demands by Service Type for Winter 2022/2023

Service Type	Demands (TJ/d)
General Service (firm)	306
Contract Rate (firm)	392
Contract Rate (Interruptible)	87
Total	785

/U

26. Enbridge Gas continues to offer customers the ability to turn back firm service and select interruptible service. This offering, if accepted, would reduce Design Day firm demands. As described in Exhibit B, Tab 1, Schedule 1, to date there has been no interest from customers to turn back firm service.

D. Panhandle System Network Analysis

27. The Panhandle System capacity for Winter 2022/2023 is 737 TJ/day[11]. The forecasted firm demand on the Panhandle System for Winter 2022/2023 is 698 TJ/day. A forecast of the Panhandle System capacity, Design Day demand, and shortfall is detailed in Table 3 below. /U

Table 3: Panhandle System Capacity, Design Day Demand, and Shortfall /U

	Historical Actuals			FORECAST								
	Winter 19/20	Winter 20/21	Winter 21/22	Winter 22/23	Winter 23/24	Winter 24/25	Winter 25/26	Winter 26/27	Winter 27/28	Winter 28/29	Winter 29/30	Winter 30/31
Panhandle System Capacity (TJ/d)	**725**	**725**	**713**	**737**	**737**	**737**	**737**	**737**	**737**	**737**	**737**	**737**
Design Day Demand Forecast (TJ/d)	**640**	**656**	**672**	**698**	**730**	**802**	**849**	**863**	**878**	**892**	**906**	**921**
Surplus (shortfall is negative) (TJ/d)	84	69	41	38	6	(66)	(112)	(127)	(141)	(156)	(170)	(184)

[11] The existing system capacity has increased since the previous forecast due to differences in the actual location of growth and changes in the energy content of the gas.

Panhandle Regional Expansion Project
DCF Analysis
InService Date: Nov-01-2024

Project Year ($000's)	Project Total	1	2	3	4	5	6	7	8	9	10
Operating Cash Flow											
Revenue	356,524	3,572	6,144	6,945	7,743	8,538	9,204	9,246	9,246	9,246	9,246
Expenses:											
O & M Expense	(5,060)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)
Municipal Tax	(34,200)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)
Income Tax	(80,857)	1,856	(692)	(1,580)	(1,792)	(2,003)	(2,179)	(2,190)	(2,190)	(2,190)	(2,190)
Net Operating Cash Flow	(120,117)	4,446	4,471	4,383	4,970	5,554	6,043	6,075	6,075	6,075	6,075
Capital											
Incremental Capital	(289,224)	(243,662)	(44,894)	(669)	-	-	-	-	-	-	-
Change in Working Capital	(6)	(6)	-	-	-	-	-	-	-	-	-
Total Capital	(289,230)	(243,668)	(44,894)	(669)	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	71,580	4,321	8,024	6,902	5,934	5,127	4,451	3,884	3,404	2,997	2,650
Net Present Value											
PV of Operating Cash Flow	89,954	4,321	4,105	3,803	4,074	4,300	4,420	4,198	3,966	3,746	3,539
PV of Capital	(286,677)	(243,668)	(42,413)	(597)	-	-	-	-	-	-	-
PV of CCA Tax Shield	46,796	4,201	7,368	5,988	4,863	3,969	3,256	2,684	2,222	1,848	1,544
Total NPV by Year	(149,927)	(235,146)	(30,939)	9,194	8,937	8,269	7,676	6,881	6,188	5,594	5,083

Project NPV	**(149,927)**
Project PI	**0.48**

Panhandle Regional Expansion Project
DCF Analysis
InService Date: Nov-01-2024

Project Year ($000's)	Project Total	11	12	13	14	15	16	17	18	19	20
Operating Cash Flow											
Revenue	356,524	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246
Expenses:											
O & M Expense	(5,060)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)
Municipal Tax	(34,200)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)
Income Tax	(80,857)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)
Net Operating Cash Flow	(120,117)	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075
Capital											
Incremental Capital	(289,224)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(6)	-	-	-	-	-	-	-	-	-	-
Total Capital	(289,230)	-	-	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	71,580	2,353	2,097	1,876	1,683	1,514	1,367	1,236	1,121	1,018	927
Net Present Value											
PV of Operating Cash Flow	89,954	3,343	3,158	2,983	2,819	2,663	2,516	2,376	2,245	2,121	2,004
PV of Capital	(286,677)	-	-	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	46,796	1,295	1,090	921	781	664	566	484	414	355	306
Total NPV by Year	(149,927)	4,638	4,249	3,905	3,599	3,327	3,082	2,860	2,659	2,476	2,309

Project NPV	**(149,927)**
Project PI	**0.48**

Panhandle Regional Expansion Project
DCF Analysis
InService Date: Nov-01-2024

Project Year ($000's)	Project Total	21	22	23	24	25	26	27	28	29	30
Operating Cash Flow											
Revenue	356,524	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246
Expenses:											
O & M Expense	(5,060)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)
Municipal Tax	(34,200)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)
Income Tax	(80,857)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)
Net Operating Cash Flow	(120,117)	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075
Capital											
Incremental Capital	(289,224)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(6)	-	-	-	-	-	-	-	-	-	-
Total Capital	(289,230)	-	-	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	71,580	845	771	705	645	591	542	497	457	420	386
Net Present Value											
PV of Operating Cash Flow	89,954	1,893	1,788	1,689	1,596	1,507	1,424	1,345	1,271	1,201	1,134
PV of Capital	(286,677)	-	-	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	46,796	263	227	196	170	147	127	110	96	83	72
Total NPV by Year	(149,927)	2,156	2,015	1,885	1,765	1,654	1,551	1,456	1,367	1,284	1,206

Project NPV	**(149,927)**
Project PI	**0.48**

Panhandle Regional Expansion Project
DCF Analysis
InService Date: Nov-01-2024

Project Year ($000's)	Project Total	31	32	33	34	35	36	37	38	39	40
Operating Cash Flow											
Revenue	356,524	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246
Expenses:											
O & M Expense	(5,060)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)
Municipal Tax	(34,200)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)
Income Tax	(80,857)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)
Net Operating Cash Flow	(120,117)	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075
Capital											
Incremental Capital	(289,224)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(6)	-	-	-	-	-	-	-	-	-	-
Total Capital	(289,230)	-	-	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	71,580	355	327	301	277	255	235	217	200	185	481
Net Present Value											
PV of Operating Cash Flow	89,954	1,072	1,012	956	903	853	806	762	720	680	642
PV of Capital	(286,677)	-	-	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	46,796	63	54	47	41	36	31	27	24	21	142
Total NPV by Year	(149,927)	1,134	1,067	1,004	945	889	838	789	743	700	784

Project NPV	**(149,927)**
Project PI	**0.48**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit E, Tab 1, Schedule 6

Question:

(a) Please provide all spreadsheets and detailed calculations underlying Exhibit E, Tab 1, Schedule 6. Please include live excel spreadsheets.
(b) Please provide Enbridge's best forecast of gas prices starting at the in-service date for (i) 20 years and (ii) 40 years.
(c) Please approach the gas supply group and the DSM group and ask them to provide their best forecast of gas prices.
(d) Please provide ICF's latest annual gas price forecast. As this is proprietary, this can be provided confidentially. Please also provide the forecast as percent increases and apply those values to the prices in the relevant area.
(e) Please describe how Enbridge generated its electricity price, including underlying calculations.
(f) Please provide Enbridge's best forecast of electricity prices starting at the in-service date for (i) 20 years and (ii) 40 years.
(g) Please justify the assumption that the carbon tax will remain at $170 from 2031 to 2063. How confident is Enbridge in this prediction?
(h) Please confirm that Enbridge estimated the cost of electric heating on the assumption that resistance heating is used, not a high efficiency heat pump.
(i) Please describe the methodology used to generate Exhibit E, Tab 1, Schedule 6. Please also how this meets the requirements in E.B.O. 134 with specific references to the relevant sections of E.B.O. 134.
(j) Please confirm whether Enbridge used customer-facing prices or avoided costs in this analysis. Please provide Enbridge's understanding of what E.B.O. 134 requires in this regard.
(k) Please confirm that in the stage 2 analysis in EB-2016-0186 (Panhandle Reinforcement Project), which was filed in June if 2016, Union Gas used the following assumption: "Gas and alternative fuel prices are the average posted prices for the 12 month period June 2015 to May 2016."

Response

a) Please see Attachment 1.

b) - d)
Please see the response at Exhibit I.PP.11. Enbridge Gas is not able to produce the forecast information sought by ED at this time.

e) Enbridge Gas generated its electricity pricing based upon the posted electricity pricing from the Ontario Energy Board website for the year 2021.[1] The posted pricing was converted from a cents per kilowatt hour to a dollar per gigajoule. The dollar per gigajoule was then converted to a dollar per m^3 assuming a heat content of 0.03932 GJ per m^3. Please see Attachment 2 to this response for the supporting calculation.

f) Enbridge Gas is not able to produce the forecast information sought by ED at this time. Electricity prices can be found at the IESO website, and any questions regarding electricity prices are more appropriately directed to the IESO: https://www.ieso.ca/en/Power-Data/Monthly-Market-Report

g) To date, the Government of Canada has only announced the annual carbon price to 2030; however, the updated pricing has not been included in the Greenhouse Gas Pollution Pricing Act. Further, the Government of Canada has not provided any indication if carbon pricing will continue in 2031 or beyond, or at what rates. Absent this information, Enbridge Gas has assumed that carbon pricing will continue beyond 2030 remaining at a cost of $170 per tonne.

h) The Stage 2 analysis does not consist of an explicit variable related to the type of end-use equipment, for any fuel types. Enbridge Gas does not believe E.B.O. 134 identifies a specific requirement in this regard. Please see parts a) and e) above for more information on the methodology employed.

i) The Stage 2 analysis determines the net present value of the difference in energy prices of alternative energy sources (heating oil, propane, electricity) versus natural gas. The price difference is applied to the forecast natural gas energy that the Project will provide to future general service customers. This aligns with E.B.O. 134 paragraph 6.74 which states:

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[1] https://www.oeb.ca/consumer-information-and-protection/electricity-rates/historical-electricity-rates

> The second stage should be designed to quantify other public interest factors not considered at stage one. All quantifiable other public interest information as to costs and benefits should be provided at the stage.[2]

This methodology has been accepted by the OEB in numerous past applications. For details on the methodology used to develop Exhibit E, Tab 1, Schedule 6, please refer to part a) above.

j) Enbridge Gas used retail costs in this analysis (please see the response to Exhibit I.STAFF.15 c) part iii). Enbridge Gas does not believe that E.B.O. 134 identifies a specific requirement in this regard.

k) Confirmed.

[2] Ontario Energy Board, E.B.O. 134 Report of the Board, June 1, 1987, paragraph 6.74

				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Incremental Growth	Constant	**Units**	**Total**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Discount Rate	4.00%																						
Discount Factor (Mid Period)	0.5000			0.9806	0.9429	0.9066	0.8717	0.8382	0.8060	0.7750	0.7452	0.7165	0.6889	0.6624	0.6370	0.6125	0.5889	0.5663	0.5445	0.5235	0.5034	0.4840	0.4654
Assumed Mix of Alt Fuel Market Share if Gas Not Available																							
Residential & Commercial																							
Heating Oil	%			24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
Propane	%			10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Electricity	%			67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Total				100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Energy Prices	$/m^3	Gas $/m^3	Diff $/m^3																				
Natural Gas	0.144			0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438
Heating Oil	1.169	0.14	1.0257	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695
Propane	0.968	0.14	0.8247	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684
Electricity	1.102	0.14	0.9581	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019
Factors for Carbon Calc																							
Natural Gas	0.001958																						
Heating Oil	0.002872																						
Propane	0.002384																						
Electricity	-																						
Carbon Cost Estimate (ICF)	$/ ton			65	80	95	110	125	140	155	170	170	170	170	170	170	170	170	170	170	170	170	170
Cost of Carbon Applied to Fuel Price Forecast																							
Natural Gas	$/ M3			0.1273	0.1566	0.1860	0.2154	0.2448	0.2741	0.3035	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329
Heating Oil	$/ M3			0.1867	0.2298	0.2728	0.3159	0.3590	0.4021	0.4451	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882
Propane	$/ M3			0.1550	0.1907	0.2265	0.2623	0.2980	0.3338	0.3695	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053
Electricity	$/ M3			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Trigger to Apply Carbon Cost	1			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Fuel Prices Applied																							
Natural Gas				0.2710	0.3004	0.3298	0.3591	0.3885	0.4179	0.4473	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766
Heating Oil				1.3561	1.3992	1.4423	1.4854	1.5285	1.5715	1.6146	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577
Propane				1.1234	1.1592	1.1949	1.2307	1.2664	1.3022	1.3380	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737
Electricity				1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019
YoY change Incremental Growth Residential	10^3M^3/Yr		15,143	1,264	2,525	2,523	2,523	2,523	2,523	1,262													
YoY change Incremental Growth Small Commercial	10^3M^3/Yr		5,708	476	951	951	951	951	951	476													
YoY change Incremental Growth Large Commercial	10^3M^3/Yr		3,358	280	560	560	560	560	560	280													
YoY change Incremental Growth Small Industrial	10^3M^3/Yr		44	7	7	7	7	7	7	-													
Total YoY Gen Serv Incremental Growth	10^3M^3/Yr		24,253	2,026	4,044	4,041	4,041	4,041	4,041	2,017	-	-	-	-	-	-	-	-	-	-	-	-	-
Cumulative Growth Residential	10^3M^3/Yr		863,155	1,264	3,789	6,312	8,835	11,358	13,881	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143
Cumulative Growth Small Commercial	10^3M^3/Yr		325,377	476	1,427	2,378	3,330	4,281	5,233	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708
Cumulative Growth Large Commercial	10^3M^3/Yr		191,397	280	839	1,399	1,959	2,518	3,078	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358
Cumulative Growth Small Industrial	10^3M^3/Yr		2,513	7	15	22	29	36	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Total Cummulative Gen Serv Incremental Growth	10^3M^3/Yr		1,382,442	2,026	6,070	10,111	14,153	18,194	22,236	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253
Assumed Fuel Mix	$/ M3																						
Heating Oil	$1.17			24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
Propane	$1.10			10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Electricity	$0.97			67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Weighted Cost of Alt Fuels	$/ M^3			$1.16	$1.18	$1.19	$1.21	$1.22	$1.23	$1.25	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26
Cost of Gas	$/ M^3			$0.27	$0.30	$0.33	$0.36	$0.39	$0.42	$0.45	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Difference	$/ M^3			$0.89	$0.88	$0.86	$0.85	$0.83	$0.81	$0.80	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78
Cumulative Gen Serv & Contract	10^3M^3/Yr			2,026	6,070	10,111	14,153	18,194	22,236	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253
Alt Fuel Saving	$/ M^3			0.89	0.88	0.86	0.85	0.83	0.81	0.80	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78
Res & Comm Fuel Savings with Gas	$ 000's			1,811	5,328	8,716	11,978	15,113	18,120	19,383	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002
Discount Factor (Mid Period)				0.981	0.943	0.907	0.872	0.838	0.806	0.775	0.745	0.717	0.689	0.662	0.637	0.612	0.589	0.566	0.544	0.524	0.503	0.484	0.465
Fuel Savings Discounted				1,775	5,024	7,902	10,442	12,667	14,604	15,021	14,160	13,615	13,091	12,588	12,104	11,638	11,191	10,760	10,346	9,948	9,566	9,198	8,844
Cumulative Fuel Savings: Discounted	$ 000's			1,775	6,799	14,701	25,143	37,810	52,415	67,436	81,595	95,210	108,302	120,890	132,993	144,631	155,822	166,582	176,928	186,877	196,442	205,640	214,484

NPV Term (yrs)	20	40
NPV of Fuel Savings $millions	214	335

				2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062
Incremental Growth	Constant	**Units**	**Total**	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Discount Rate	4.00%																						
Discount Factor (Mid Period)	0.5000			0.4475	0.4303	0.4138	0.3978	0.3825	0.3678	0.3537	0.3401	0.3270	0.3144	0.3023	0.2907	0.2795	0.2688	0.2584	0.2485	0.2389	0.2297	0.2209	0.2124
Assumed Mix of Alt Fuel Market Share if Gas Not Available																							
Residential & Commercial																							
Heating Oil	%			24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
Propane	%			10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Electricity	%			67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Total				100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Energy Prices	$/m^3	Gas $/m^3	Diff $/m^3																				
Natural Gas	0.144			0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438	0.1438
Heating Oil	1.169	0.14	1.0257	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695	1.1695
Propane	0.968	0.14	0.8247	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684	0.9684
Electricity	1.102	0.14	0.9581	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019
Factors for Carbon Calc																							
Natural Gas	0.001958																						
Heating Oil	0.002872																						
Propane	0.002384																						
Electricity	-																						
Carbon Cost Estimate (ICF)	$/ ton			170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170
Cost of Carbon Applied to Fuel Price Forecast																							
Natural Gas	$/ M3			0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329	0.3329
Heating Oil	$/ M3			0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882	0.4882
Propane	$/ M3			0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053	0.4053
Electricity	$/ M3			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Trigger to Apply Carbon Cost	1			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Fuel Prices Applied																							
Natural Gas				0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766	0.4766
Heating Oil				1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577	1.6577
Propane				1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737	1.3737
Electricity				1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019

YoY change Incremental Growth Residential	10^3M^3/Yr	15,143																				
YoY change Incremental Growth Small Commercial	10^3M^3/Yr	5,708																				
YoY change Incremental Growth Large Commercial	10^3M^3/Yr	3,358																				
YoY change Incremental Growth Small Industrial	10^3M^3/Yr	44																				
Total YoY Gen Serv Incremental Growth	10^3M^3/Yr	24,253	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cumulative Growth Residential	10^3M^3/Yr	863,155	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143
Cumulative Growth Small Commercial	10^3M^3/Yr	325,377	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708	5,708
Cumulative Growth Large Commercial	10^3M^3/Yr	191,397	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358	3,358
Cumulative Growth Small Industrial	10^3M^3/Yr	2,513	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Total Cummulative Gen Serv Incremental Growth	10^3M^3/Yr	1,382,442	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253
Assumed Fuel Mix	$/ M3																					
Heating Oil	$1.17		24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
Propane	$1.10		10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Electricity	$0.97		67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Weighted Cost of Alt Fuels	$/ M^3		$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26
Cost of Gas	$/ M^3		$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Difference	$/ M^3		$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78
Cumulative Gen Serv & Contract	10^3M^3/Yr		24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253	24,253
Alt Fuel Saving	$/ M^3		0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78
Res & Comm Fuel Savings with Gas	$ 000's		19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002	19,002
Discount Factor (Mid Period)			0.448	0.430	0.414	0.398	0.383	0.368	0.354	0.340	0.327	0.314	0.302	0.291	0.280	0.269	0.258	0.248	0.239	0.230	0.221	0.212
Fuel Savings Discounted			8,504	8,177	7,862	7,560	7,269	6,990	6,721	6,462	6,214	5,975	5,745	5,524	5,312	5,107	4,911	4,722	4,540	4,366	4,198	4,036
Cumulative Fuel Savings: Discounted	$ 000's		222,988	231,165	239,027	246,587	253,856	260,846	267,567	274,029	280,243	286,217	291,962	297,486	302,798	307,905	312,816	317,538	322,078	326,444	330,641	334,678

NPV Term (yrs)	
NPV of Fuel Savings $millions	

ONTARIO ENERGY BOARD

FILE NO.: **EB-2022-0157** **Enbridge Gas Inc.**

VOLUME: **Technical Conference**

DATE: **October 6, 2022**

greenhouse, including things such as CO_2 capture in their operations that they're unable to do with -- during those periods, the reliability of fuel supply, the cost of interruptible fuel.

They've got a number of significant risks in how they think about this that are different than other types of customers. So I am speaking about that one class, Kent. But I wanted to make that point that there's a very strong preference for firm service if it is available to be taken.

MR. ELSON: My question isn't restricted to greenhouses which I understand are about 52 percent of your contract. And I am going to ask you to do something, and I think I know what the answer will be. But for the sake of the record, I need to ask it.

So I am going to ask you if you would agree to write an email or a letter to all of your contract customers to tell them that there's a capacity deficit that could trigger a project that would raise their rates, and to ask how much of their demand they would potentially agree to be interruptible and what discount on their rates they would require in order to agree to that.

Is that something that you would undertake to do?

MR. KEIZER: No, it would not be something we would undertake to do.

MR. ELSON: Okay. For the record, I think it would be a good idea, but we will leave that for later.

I will ask a question now about some further previous discussion on a distribution revenue.

if I have understood what's been done.

The achievable potential study was applied to just the general service customers, which are about 45 percent of the demand. Is that correct?

MS. WADE: The general service customers within the APS, yes, yes. It took the general service customers from the APS and we used our Union Gas rate zone. Union Gas South rate zone.

MR. ELSON: So this has estimated the energy efficiency that could be achieved if there were programs targeting just the general service customers in the Panhandle region?

MS. WADE: In the Leamington-Kingsville-Wheatley area, that's right. And the potential and the costs were determined using proxies based on the Union Gas South region which was from the APS.

MR. ELSON: But it's only applied --

MS. WADE: Not out of the APS.

MR. ELSON: But it only applied it to 45 percent of the demand i.e., the general service demand, is that correct?

MS. WADE: That's correct.

MR. ELSON: What I am asking is for it to be applied to the other 55 percent.

MS. WADE: Yes. And what we're saying is that is not meaningful or valuable, because the proxy that was applied to general service is not the same factor that you would apply to a contract customer.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 83

To advise, if Enbridge were to obtain contributions in aid of construction for the panhandle regional expansion project to bring the profitability up to 1, how much would that reduce Enbridge's proposed capital spending in each year from now to 2028.

Response:

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023. /u

The following hypothetical scenario is based on the economics for the Panhandle Regional Expansion Project as filed in the updated leave to construct application[1] absent the Stage 2 and Stage 3 benefits. In order for the project to achieve a PI of 1, a contribution in aid of construction (CIAC) of $183.0 million would be required in 2024. /u

As part of the Capital Update, Enbridge Gas is proposing a levelized approach to cost /u
recovery for PREP. Please see Exhibit 2, Tab 5, Schedule 4, page 31 for details on the /u
proposed approach. Under the levelized approach, capital expenditures have been /u
removed, therefore the CIAC of $183.0 million would have no impact on capital /u
expenditures in 2024. There would also be no impact to proposed capital spending in /u
each year from 2025 to 2028. /u

[1] EB-2022-0157.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 175

For the table in JT1.19 at page 326: (1) to add two rows to the table for figures for blue and green hydrogen in the common value of dollars per kilogram; (2) to add a column for the cumulative amount of each kind of hydrogen in the diversified scenario; (3) add some additional clarifying descriptors to the table.

Response:

The following response was provided by Guidehouse Canada Ltd.:

The following information has been added to Table 1 from Exhibit JT1.19. The Pathways to Net Zero (P2NZ) model values for domestic production of green and blue hydrogen presented in this undertaking are after-the-fact ad hoc transformations of interim model outputs calculated based on the production cost (CAPEX and OPEX) and the production volume of each type of hydrogen. Caution should be used in interpreting them or comparing them to other industry values. As discussed at TC Tr. Vol 1 178 to 182, these values are not direct outputs of Guidehouse's analysis and may not align with other industry values, given methodology differences; thus, these values likely have limited usefulness in comparison with other sources for such costs. Please note the following caveats:

1) Cost estimates for the P2NZ Study were developed to inform a "total price tag" comparison of two net-zero scenarios.
2) Costs presented here do include cost of feedstock (methane for blue hydrogen, electricity for green hydrogen), cost of equipment, and cost of emissions (for blue hydrogen).
3) Costs presented here do not include the cost of financing, taxes, profits, ROE, etc. As such, these figures are not comparable to commodity costs, market prices, or customer rates.

Table 1

/u

Type of Value	Reference	Fuel Description	2020 $/kg (real 2020$CAD)	2030 $/kg (real 2020$CAD)	2040 $/kg (real 2020$CAD)	2050 $/kg (real 2020$CAD)	Cumulative Supply / Production from P2NZ Model (million kgs) (2020-2050)
P2NZ[3]	KT1.3, page 4	Hydrogen Imports from Quebec		2.0	1.6	1.5	44
	KT1.3, page 4	Hydrogen Imports from Western Canada		2.4	2.1	1.8	142
		Ontario Green Hydrogen (Diversified Scenario)[4]	N/A	N/A	2.14	2.00	1,943
		Ontario Blue Hydrogen (Diversified Scenario)[5]	N/A	1.64	0.88	0.64	3,998
Estimate, EB-2019-0294, Exhibit I.ED.6	Exhibit I.4.2-ED-131	Estimated production cost of Hydrogen from P2G in Ontario	6.24 to 7.80[6]	4.37 to 5.46[7]			
	Exhibit I.4.2-ED-131	Retail Hydrogen price in Ontario	8.23 to 8.87[8]				
	Exhibit I.4.2-ED-131	Retail hydrogen price in California	16.01 to 21.11[9]				
	Exhibit I.4.2-ED-131	Retail hydrogen price in Quebec	18.04[10]				

[3] All model values converted using a lower heating value of 119.88 MJ/kg. The model values are derived from the values provided at exhibit JT9.22 and Exhibit JT9.22 Attachment 1.
[4] Derived from Model Output: This is the derived supply cost that best represents a proxy for commodity cost. Annual electrolyzer costs (average annual CAPEX by decade and annual O&M) plus cost of electricity needed, divided by annual hydrogen production via electrolyzers.
[5] Derived from Model Output: This is the derived supply cost that best represents a proxy for commodity cost. Annual SMR costs (average annual CAPEX by decade and annual O&M) divided by annual hydrogen production via SMR.
[6] Based on assumptions as specified in EB-2019-0294, Exhibit 1.ED.6 (g) and converted to kg using a higher heating value of 141.88 MJ/kg.
[7] Assumed a net reduction of 30%, as specified in EB-2019-0294 (h), and converted to kg using a higher heating value of 141.88 MJ/kg.
[8] Based on information provided in EB-2019-0294, Exhibit 1.ED.6 (l), and converted to kg using a higher heating value of 141.88 MJ/kg.
[9] Based on information provided in EB-2019-0294, Exhibit 1.ED.6 (k) and converted to kg using a higher heating value of 141.88 MJ/kg.
[10] Based on information provided in EB-2019-0294, Exhibit 1.ED.6 (m) and converted to kg using a higher heating value of 141.88 MJ/kg.

REPORT OF THE BOARD

E.B.O. 134

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1980, Chapter 332;

AND IN THE MATTER OF a Review by the Ontario Energy Board of the Expansion of the Natural Gas System in Ontario.

BEFORE:

J.C. Butler
Vice-Chairman and
Presiding Member

J.A. DeKort
Member

M.A. Daub
Member

REPORT OF THE BOARD

June 1, 1987

ISBN 0-7729-2610-7

an expanded feasibility test which mirrors the rate of return approach by which the utilities are regulated.

Union

6.10 Union opposed the use of this test for evaluation of its system expansion projects.

Brant County Federation of Agriculture and Town of Kincardine

6.11 Both these Participants expressed concern with the five-year rate of return test as they felt that the five-year period should be extended.

Other Economic Feasibility Tests Presently In Use

6.12 Union and Consumers' use DCF analysis to assess the economic feasibility of most projects. DCF tests relate the net present value of the cash in-flows generated from a project to the net present value of its capital costs and other cash out-flows. The discounting of cash in-flows and out-flows gives recognition to the time value of money (i.e. that a dollar spent today has a different value than a dollar spent in the future).

6.13 Most of the DCF tests employed by Union and Consumers' evaluate incremental costs and revenues of system expansion projects over their

6.41 The Board is further concerned that the calculation of the utilities' system replacement costs would be time consuming and imprecise.

6.42 In the opinion of the Board, Union's alternative tests are too narrow in scope to fully assess all the quantitative and qualitative costs and benefits of system expansion.

6.43 The second suggested test does not quantify the magnitude of the subsidy required from the utility's existing customers and has the same faults regarding public interest factors as the Cost Test itself.

The Benefit Test

6.44 The Benefit Test provides an analytical two-stage cost-benefit framework for evaluating system expansion projects. The first stage is a DCF financial feasibility test. This test is similar to the DCF tests presently employed by Consumers' and Union with the notable exception that a social discount rate is used instead of the utility's cost of capital.

6.45 At the second stage, the customer benefits and costs of a system expansion project are compared. The benefits of system expansion are mainly the fuel cost savings of the new gas customers. The cost to the existing customers of proceeding with a system expansion project which does not satisfy the DCF analysis is an increase in their gas bills. Both the costs and the benefits of a project would be discounted by the social discount rate used in the DCF analysis. If the present value of the customer benefits is greater than or equal to the present value of the customer costs, then the project could be accepted.

Participants' Positions on the Benefits Test

Consumers'

6.46 Consumers' submitted that the major strength of the Benefit Test is that it considers the broad effects beyond the pure economics of adding incremental projects to the system.

6.47 The company also asserted that the test provides a satisfactory indicator properly balancing factors over the life of the project.

6.48 Consumers' submitted that the main problem will be in determining and justifying the social discount rate.

6.49 Consumers' expressed concern that some customer benefits are not quantifiable.

ICG

6.66 ICG conceded that this test seems to be an improvement over the Benefit Test. However, ICG stated that it did not endorse any of the Alternative Tests but preferred to modify its existing fifth-year rate of return test. It considered that the proper forum for deciding whether or not to change the current test is a public hearing involving an application, not at a technical conference. ICG also expressed the hope that any new guidelines adopted by the Board would be restricted to information requirements only and that the utilities would retain the right to present this information as they see fit.

The Board's Findings on Economic Feasibility Tests

6.67 The Board finds that of the tests currently in use by the utilities, the DCF analysis provides a superior measure of the subsidy required from existing customers for a particular project.

6.68 The Board directs all utilities to employ DCF analysis as part of its assessment of the feasibility of projects for system expansion.

6.69 The Board encourages the use of more formal risk measurement in the feasibility test and it would not discourage the use of sensitivity analyses of variables being regularly employed in the test.

6.70 The Board finds that incremental costs should be used in evaluating the feasibility of system expansion.

6.71 The Board will continue to assess the adequacy of the DCF analysis and any other tests used for project evaluation at the time of a utility's rate case hearing.

6.72 The Board finds that Union's three-stage test has considerable merit. The Board requires each utility to develop a three-stage process as outlined below to aid the Board in its determination of the public interest.

6.73 The first stage is a test based on a DCF analysis.

6.74 The second stage should be designed to quantify other public interest factors not considered at stage one. All quantifiable other public interest information as to costs and benefits should be provided at this stage.

6.75 The third stage should take into account all other relevant public interest factors plus the results from stage one and stage two.

6.76 A project could, therefore, be accepted if it passed the DCF analysis of stage one and if the disadvantages and quantifiable costs from stages two and three do not disqualify it. If a project is not acceptable because it fails the DCF analysis or has significant other disadvantages, then stages two and three must be completed before the project can be said to be fully evaluated.

6.77 The Board is aware that each utility will continue to approve internally projects that lie within areas for which a franchise and a certificate of public convenience and necessity have been issued. At subsequent rate hearings the Board may assess the analyses employed before approving the inclusion in rate base of any specific project.

6.78 Any project brought before the Board for approval should be supported by all data used by the Applicant in reaching its conclusion that the project is viable. The utilities and other interested parties may use alternative analyses, but these and the results must be presented at the relevant hearing. The Board will continue to weigh the various benefits against the various disadvantages as it always has in reaching its decision in the public interest.

6.79 The Board continues to hold the opinion that it is appropriate for existing customers to subsidize, through higher rates, financially non-sustaining extensions that are in the overall public interest if the subsidy does not cause an undue burden on any individual, group or class.

7.28 The Board notes that several projects that received DSEP funding did not meet the fifth-year rate of return test. Nevertheless the Board accepted that the projects were in the public interest and approved these projects even though a subsidy would still be required from existing customers in the fifth year of the project.

7.29 The Board finds that a contribution-in-aid of construction should be required for those projects where the sole purpose is to supply gas into a new area and where the evaluation process demonstrates an undue burden on existing customers.

7.30 The Board would expect an agreement to be reached between the utility and the community regarding the contribution before an application is made to the Board.

7.31 In certain cases, the Board considers that special rates and/or loans by the utility to finance a contribution-in-aid of construction, may facilitate the expansion of the natural gas system.

7.32 A number of the participants strongly suggested that the provincial government encourage expansion of the natural gas system in Ontario by

THE BIG SWITCH

POWERING CANADA'S NET ZERO FUTURE

MAY 2022

CANADIAN CLIMATE INSTITUTE
L'INSTITUT CLIMATIQUE DU CANADA

01 *The big switch*

Clean electricity will power Canada's net zero transition.

Reaching Canada's climate targets requires a *big switch* from fossil fuel energy to clean electricity. This switch involves producing more clean electricity in every region, phasing out greenhouse gas-emitting sources, and using clean electricity to power more and more of our homes, vehicles, businesses, and industries. It will underpin Canada's climate progress and power Canada's future prosperity.

Getting there, however, will require governments at all orders to leverage their policy tools—ideally in a coordinated way.

The Canadian Climate Institute's electricity project—including this summary report and the two detailed reports on which it's based—explores both the technical and policy changes needed to align Canada's electricity systems with net zero, detailing the technologies needed to build electricity systems that are *bigger, cleaner, and smarter* (*Section 2*), and identifying the policies needed to bring about an *electric federalism* that can drive Canada's big switch (*Section 3*).

1.1 *Net zero and the big switch*

In our 2021 report *Canada's Net Zero Future*, the Canadian Climate Institute found that clean electricity and electrification—substituting fossil fuels with clean electricity to power more and more of our economy—underpin *all* credible economy-wide pathways to net zero (Dion et al. 2021). We found that electricity will play a central and driving role even under best-case scenarios for emerging alternative technologies. Similar studies in Canada and abroad confirm the importance of electricity in achieving net zero (EPRI 2021; ETC 2021; IEA 2021; Langlois-Bertrand et al. 2021).

This *big switch* is key to reaching Canada's climate goals: getting this right makes everything else that's required for Canada's net zero transition much more possible, affordable, and broadly beneficial.

The big switch means producing a lot more clean electricity, for two reasons. One is to replace unabated coal and natural-gas-fired electricity as they are phased out. The other is to meet the growing need for clean electricity as Canadians switch from gasoline-powered vehicles to electric vehicles, gas stoves to induction stoves, and natural gas furnaces and boilers to heat pumps and electric furnaces. (See *Figure A* for the impact these changes will have on household energy sources.)

In addition to making electricity systems bigger and cleaner, the big switch also requires making them smarter. This means making both supply and demand more flexible to support more variable supply such as solar and wind and to respond to changing weather conditions and disruptions—including from extreme weather events driven by climate change (Clark and Kanduth 2022).

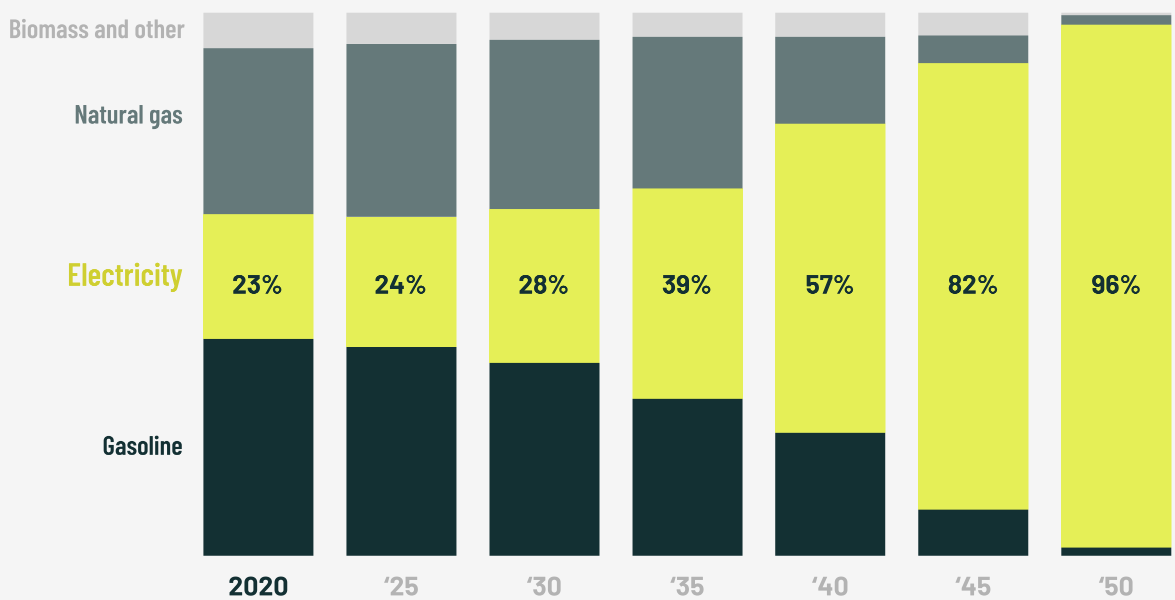
A focus on electricity systems

Our reports focus specifically on electricity systems and what is needed to make them bigger, cleaner, and smarter. Electricity systems refer to the various networks of infrastructure, institutions, and players associated with the generation, transmission, and distribution of electricity in Canada, along with the demand-side technologies and interventions that can help shift and reduce demand to minimize the need for more supply. We speak of systems, plural, recognizing that Canada does not have one single electricity system but rather numerous regional systems that are primarily managed at the provincial and territorial levels.

FIGURE A.

To support net zero, household energy use will shift away from natural gas and gasoline toward electricity

Average household share of energy consumption by type



Source. Dion et al. 2021.

1.2 *The stakes in transforming Canada's electricity systems*

Because the switch we're discussing impacts how nearly every Canadian household and business will use energy, the policy choices that Canadian governments make to align electricity systems with net zero are extremely consequential. Getting it right—or wrong—will have big implications far beyond the electricity sector, for the reasons that follow.

1. Multiple studies have reached the same conclusion: **Acting early with smart policies can significantly reduce overall costs and make achieving net zero easier.** Electricity transformations will require significant capital investment. Early and effective action, including initiatives to make electricity systems more resilient to

the effects of climate change, allows Canada to avoid a more difficult transition later, which would entail higher consumer prices from stranded assets and from underbuilt systems struggling to keep up with growing demand. Acting now also reduces overall costs by driving innovation, which can improve the cost and availability of important technologies and accelerate learning curves through deployment and use. Finally, the federal government's 2035 deadline for achieving a net zero electricity system leaves no room for delay.

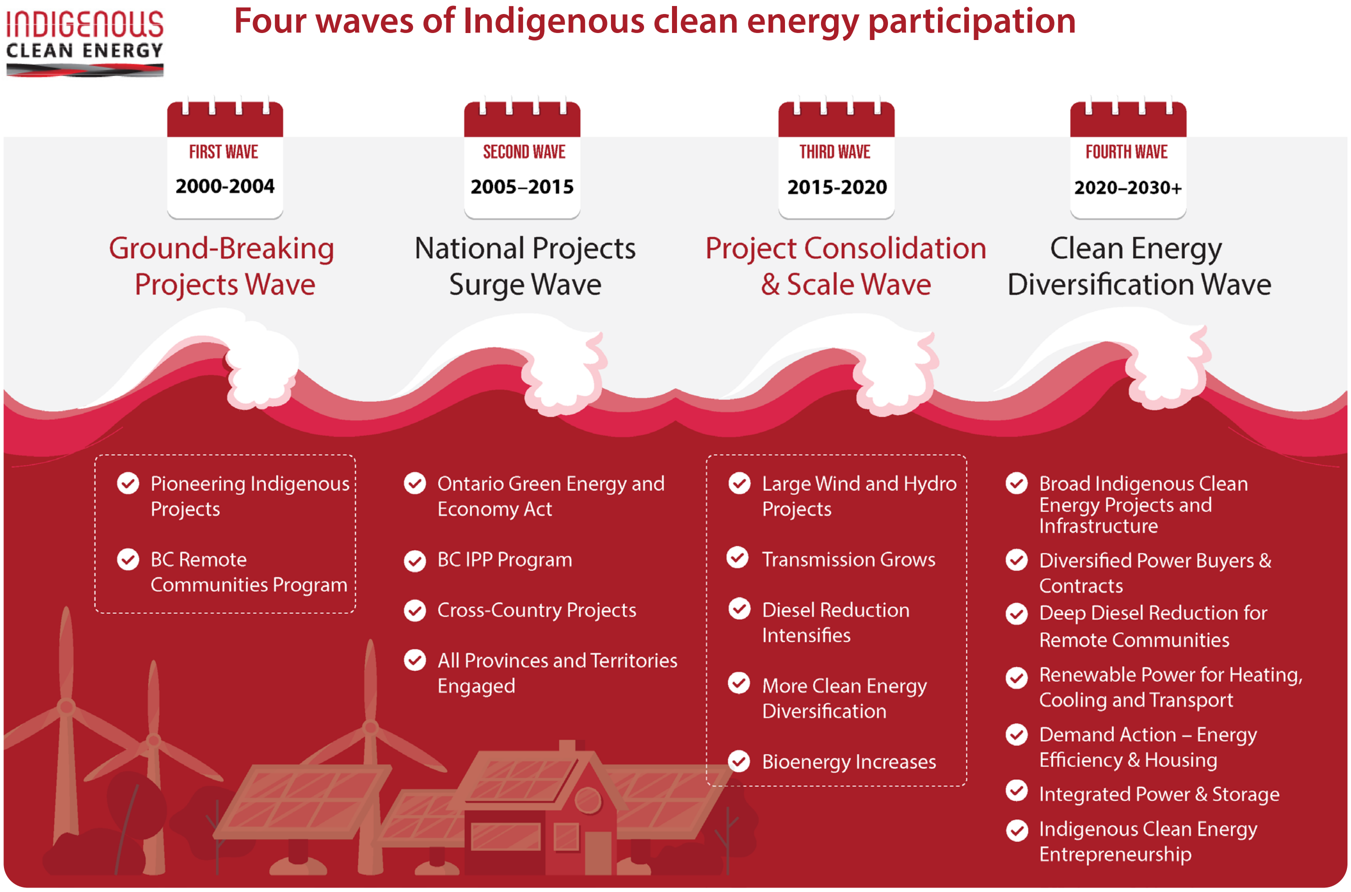
2. **Strategic action today can unlock clean growth opportunities.** According to the Climate Institute report *Sink or Swim* (Samson et al. 2021), Canadian companies active in low-carbon electricity, batteries and storage, and solar and wind equipment are well-positioned to grow in the global low-carbon transition. New sources of transition-consistent growth can offer export opportunities, employment, and prosperity for Canadians.

3. **Electricity system transformations can be pursued in ways that support equity.** Absent equity-focused policy interventions, utilities' investments in new technologies and infrastructure upgrades could increase electricity rates in ways that disproportionately impact lower-income households. Ensuring rates remain reasonable for low-income households (alongside measures to support households' ability to adopt electrification technologies) could help address these potential inequities.

4. **Catalyzing Indigenous participation and leadership can support Indigenous self-determination and reconciliation.** Indigenous communities, governments, and organizations across Canada have positioned themselves as leaders in Canada's clean energy transition. Clean energy projects represent an important means of advancing not only energy transition but reconciliation and the rights and well-being of Indigenous Peoples. As Indigenous Clean Energy describes in *Waves of Change: Indigenous clean energy leadership for Canada's clean, electric future*, the next wave of Indigenous participation and leadership in the sector will present significant new opportunities for Indigenous communities in Canada (see *Figure B*) (ICE 2022).

While the stakes are high, Canada is fortunate to have significant advantages to draw on in this transition. Over 80 per cent of electricity

FIGURE B.



Source. ICE 2022.

production in Canada is already non-emitting, in significant part due to the country's abundant hydroelectric resources (Statistics Canada 2022). And electricity systems across the country are supported by robust institutions and structures that deliver electricity that is reliable and affordable by most international standards. Building on these advantages can ensure Canada meets its climate goals while strategically positioning its economy to succeed in the global low-carbon transition.

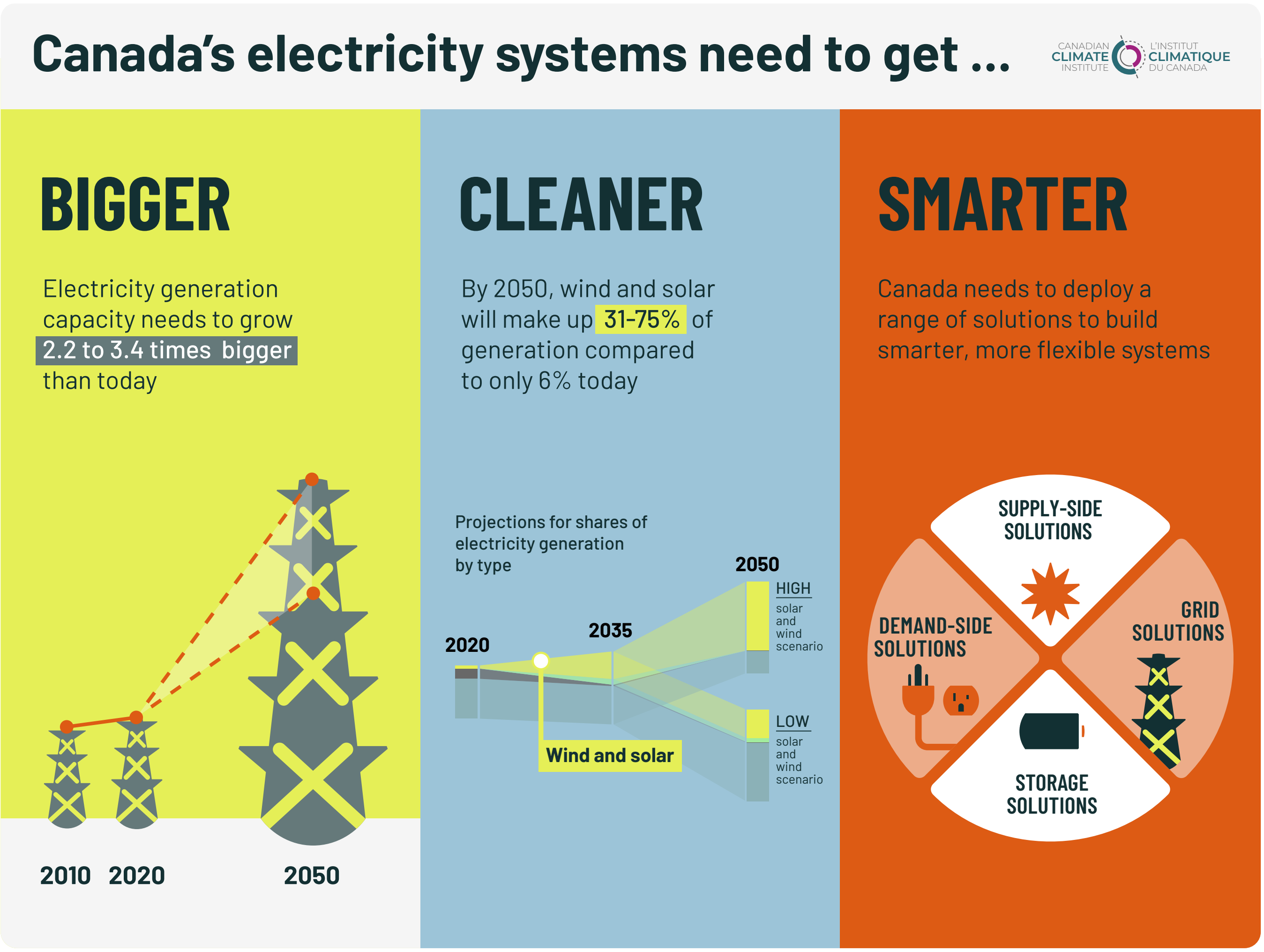
That doesn't mean that the big switch will be easy. Building out bigger, cleaner, and smarter electricity systems in every province and territory is a massive undertaking. Doing so will require grappling with the fact that different provinces and territories have unique electricity systems that face unique challenges. And it will require implementing policies that create outcomes that are effective, cost-effective, and fair.

02 *Powering the switch: Bigger, cleaner, and smarter electricity systems*

This section summarizes the findings of our technical report *Bigger, Cleaner, Smarter*, describing the changes needed in Canada's electricity systems to align them with net zero. Our report draws on a review of the most significant recent studies of electricity system transformation in Canada, as well as our project's widespread consultation with experts, thought leaders, and practitioners (see *Annex*). Overall, we find that transformation of electricity systems is both achievable and necessary to support the goal of net zero emissions economy-wide by 2050. In particular, aligning electricity systems with net zero requires attention to all three changes—bigger, cleaner, and smarter—not just the most obvious change of becoming cleaner (i.e., getting electricity generation to net zero). (See *Figure C.*)

We unpack each of these changes below.

FIGURE C.


Canada's electricity systems need to get ...
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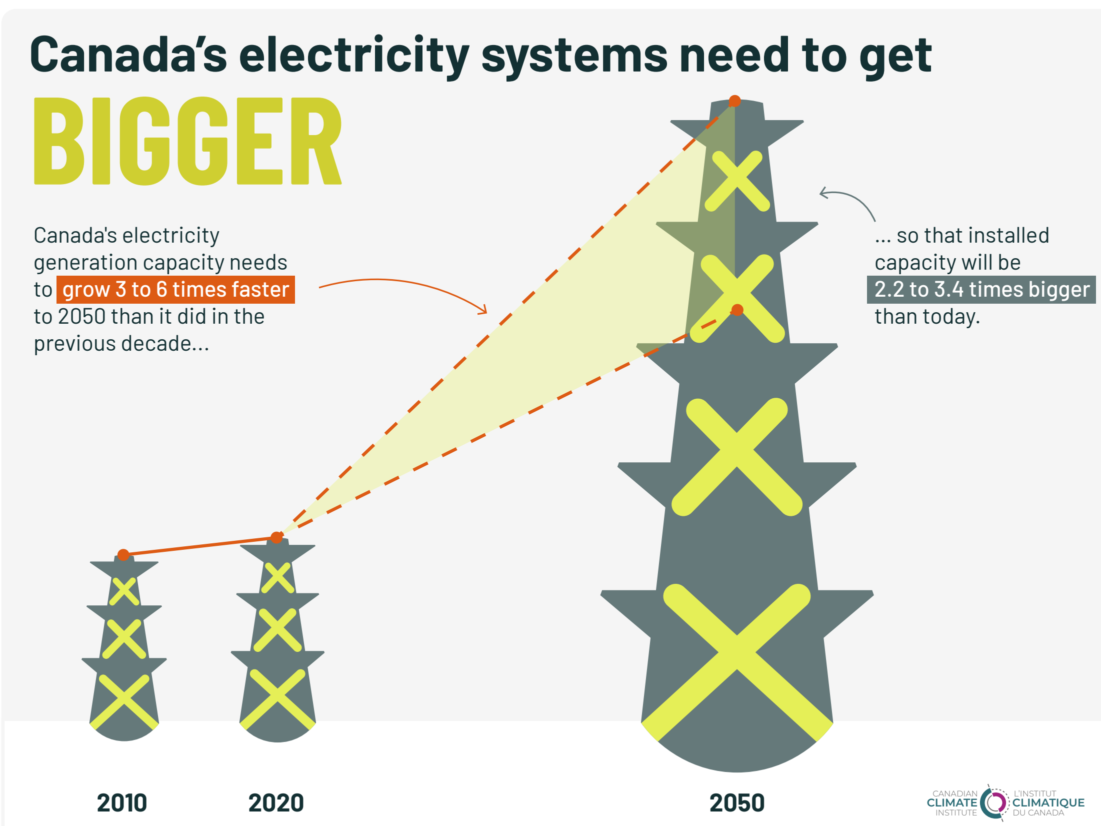
BIGGER
Electricity generation capacity needs to grow 2.2 to 3.4 times bigger than today
2010
2020
2050
CLEANER
By 2050, wind and solar will make up 31-75% of generation compared to only 6% today
Projections for shares of electricity generation by type
2020
2035
2050
HIGH solar and wind scenario
LOW solar and wind scenario
Wind and solar
SMARTER
Canada needs to deploy a range of solutions to build smarter, more flexible systems
SUPPLY-SIDE SOLUTIONS
DEMAND-SIDE SOLUTIONS
GRID SOLUTIONS
STORAGE SOLUTIONS

2.1 *Bigger*

1. Generation capacity or simply capacity is the maximum amount of electricity that a generator or system can produce, measured in watts (e.g. MW, kW). It measures the technical capability to produce electricity. This stands in contrast to generation, which refers to the actual amount of electricity produced during a certain time period, measured in watt-hours (e.g. kWh, MWh). Capacity grows more than generation (and demand) in large part because future electricity systems will have higher shares of solar and wind, which require more capacity to produce the same amount of electricity compared to thermal sources because of their greater variability.

Making electricity systems *bigger* means growing them so they can meet the increased demand created by widespread electrification. Specifically, studies show that electricity demand will be 1.6 to 2.1 times larger in 2050 compared to today, on a path to net zero. Meanwhile, the capacity of Canadian electricity systems—the maximum amount of electricity that a system can technically produce—needs to grow even more, at least doubling, if not more than tripling, over the same time frame.[1] Aggressive improvements in energy efficiency are needed so Canada's electricity systems meet electricity demand that is "right sized." Yet even with significant efficiency improvements, electricity systems must grow substantially for a net zero world. In fact, Canada must, on average, grow system capacity at a rate 3 to 6 times faster to 2050 compared to the previous decade, in order to support rising electricity demand associated with net zero (see *Figure D*).

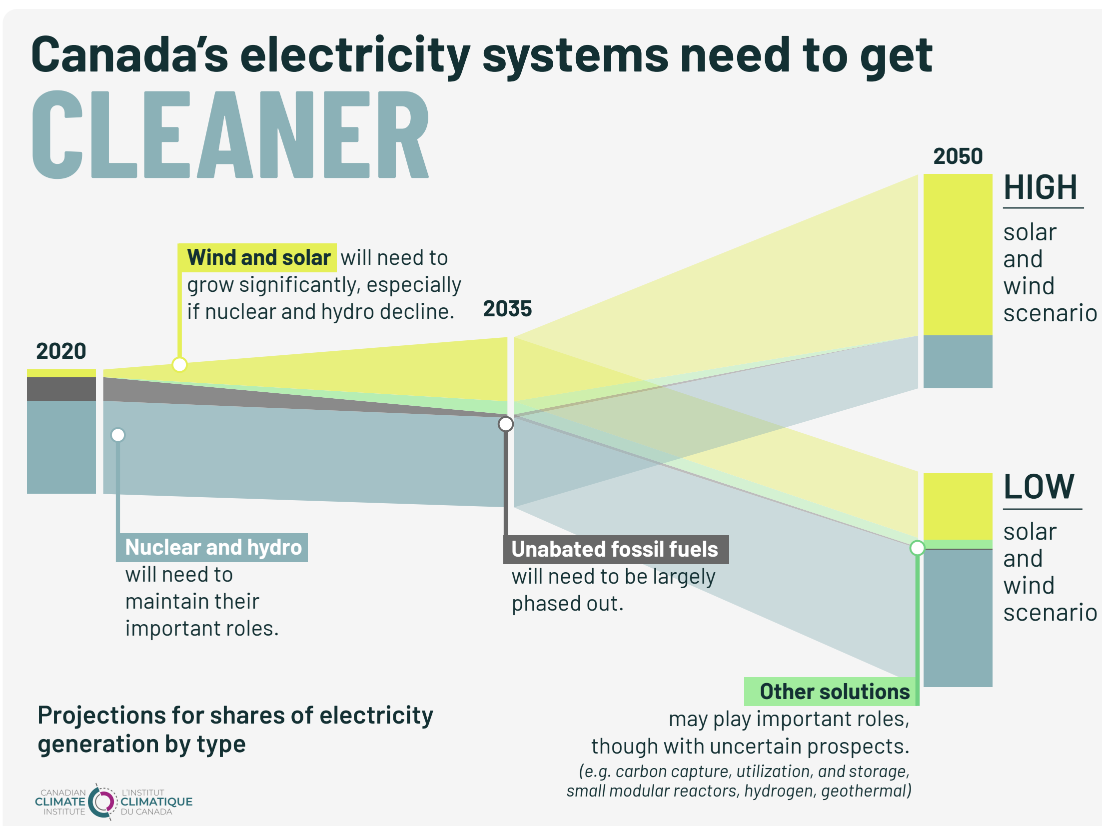
FIGURE D.



2.2 *Cleaner*

Making electricity systems *cleaner* consists of three broad elements (see *Figure E*). The first is the phase-out of generation from unabated fossil fuels, which studies show will make up no more than one per cent of total generation by 2050. Second, to replace these sources and grow systems further, accelerating growth of non-emitting electricity—especially solar and wind—is central. For instance, studies show that to support net zero, 60–95 per cent of new capacity added by 2030 must come from solar and wind. Third, hydro and nuclear power will need to maintain their important roles; otherwise, other sources of non-emitting electricity must grow even more. Several nascent technologies have high potential. These include carbon capture, utilization, and storage applied to emitting generation; small modular reactors; and hydrogen-fired electricity generation. However, there is higher uncertainty around their future role.

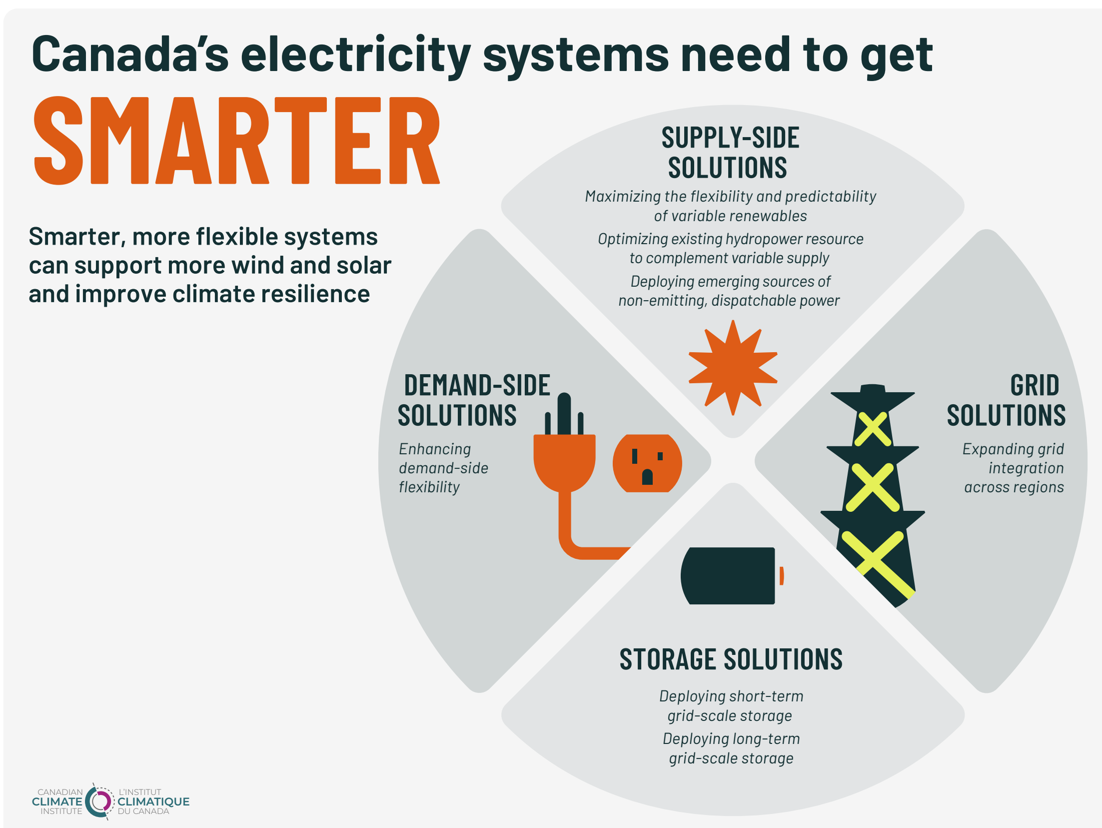
FIGURE E.



2.3 *Smarter*

Making systems *smarter* entails deploying a range of solutions so systems can become more flexible to support more solar and wind—as well as more resilient to the effects of climate change (Clark and Kanduth 2022). Supply-side sources of flexibility that can generate power on demand (hydropower in particular) will play a critical role. But other types of flexibility solutions will grow in importance on the path to net zero. Making demand for electricity more flexible, balancing out the grid with a range of sources of non-emitting electricity, scaling up the deployment of electricity storage, and enhancing integration across regions and trade of electricity through interties can all play valuable roles in a net zero future (see *Figure F*). Many of the key flexibility technologies are commercially available today. And their costs continue to fall.

FIGURE F.



2.4 *Takeaways for Canada*

Here are four takeaways from this analysis that inform the policy recommendations provided in Section 3:

1. **Aligning electricity systems with net zero is both necessary and achievable**. Making electricity systems bigger, cleaner, and smarter is technically and economically feasible. The resulting systems can reliably and affordably power Canada's economy. Moreover, because electricity underpins decarbonization across the economy, a broader transition to net zero would be far more challenging absent a transformation of electricity systems.

2. **Transformations will vary across Canada: regions without abundant hydropower resources face different challenges than those that are hydropower-rich**. The presence or absence of significant hydroelectricity resources has a particularly strong impact on the challenges each region will face. Regions without significant hydropower face challenges of decarbonizing existing supply *in addition* to growing their systems. And not having significant hydroelectricity as a domestic source of dispatchable power means they need to rely more on other sources of flexibility.

3. **Some solutions face technological barriers, while many others face social, political, or institutional ones**. Technological readiness is an important challenge for the advancement of some solutions, such as carbon capture, utilization, and storage and small modular reactors. But some of the most significant barriers to other solutions are social and institutional in nature (e.g., barriers to interregional grid integration, community acceptance of local renewable energy development). Policy to support the transformation of electricity systems needs to address both the technical and non-technical barriers to the deployment and uptake of key solutions (Turner 2021).

4. **Governments have a driving role in these transformations**. To advance the critical challenge of making electricity systems bigger, cleaner, and smarter, policy interventions from different orders of government will be required. Provincial and territorial governments are central in developing policy, given their authority over electricity systems, while the federal government can set the national policy framework and act as an enabler of regional

> progress. Meaningful involvement of Indigenous Peoples in policy making and key decisions will also be required to achieve successful transformations and to ensure Indigenous Peoples continue to take a leading role in identifying and seizing clean energy opportunities (ICE 2022).

The key takeaways are these: the changes that are needed to align Canada's electricity systems with net zero are clear, acting quickly is much better than acting slowly, and the technical solutions required are already available. The most important thing now is that Canada gets on with the task ahead: building clean supply, especially solar, wind, and storage; phasing out generation from unabated fossil fuels; and making systems more flexible. Moving rapidly toward net zero requires that policy makers recognize the centrality of clean electricity in getting Canada there, and act accordingly.

The next section presents a policy package designed to do just that.

03 *Flipping the switch: Policy recommendations for electric federalism*

This section summarizes the findings and recommendations from our second report, *Electric Federalism*, which identifies how Canadian governments can drive the transformations required in electricity systems across the country to achieve net zero. We identify four key challenges and outline the policy solutions that can overcome them. To create an affordable, reliable electricity system that is consistent with net zero, provincial, territorial, and federal governments should work together.

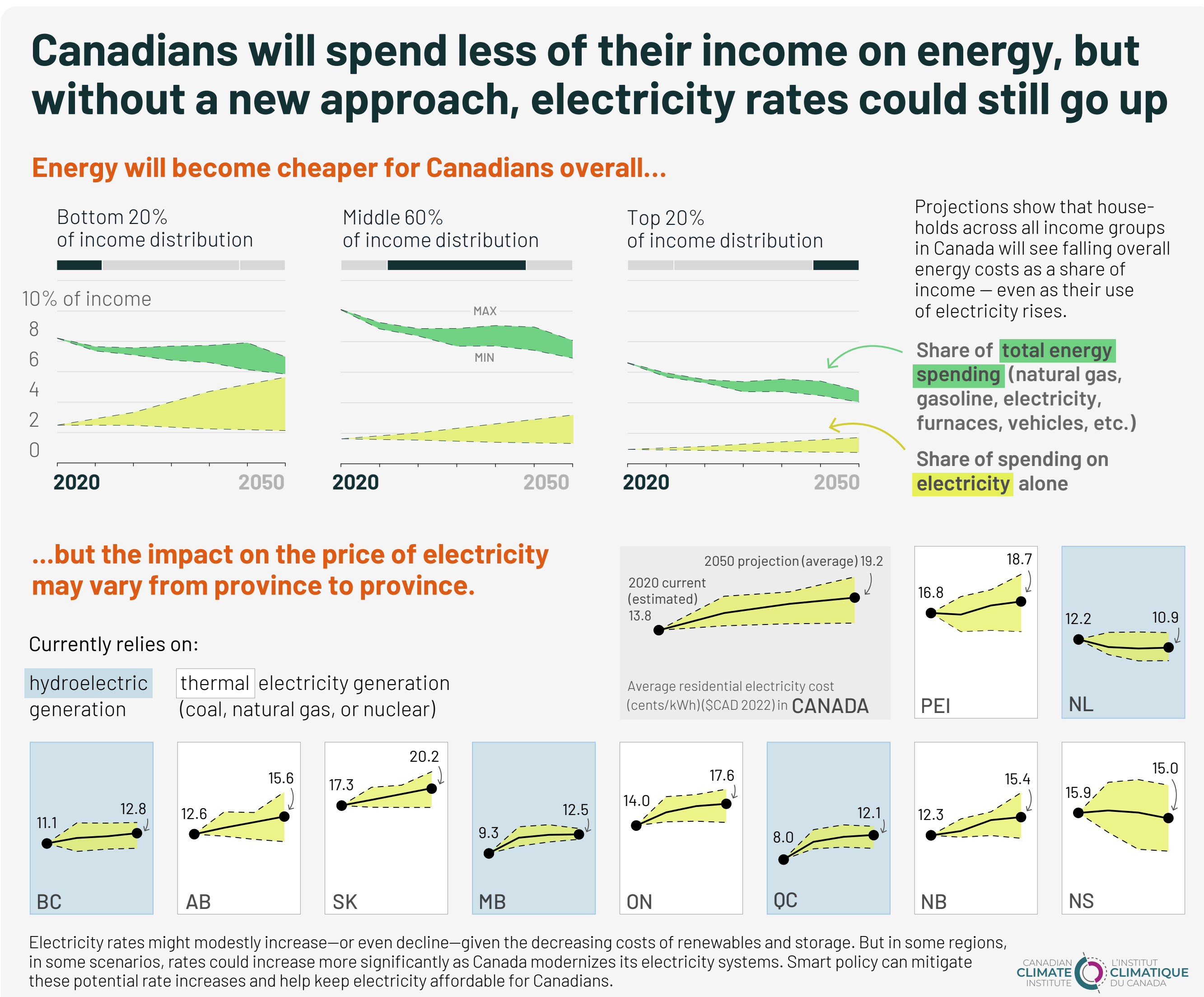
3.1 *Four challenges in aligning electricity systems with net zero*

1. **Federal climate policy in the electricity sector is not currently aligned with net zero goals**. Canada has set a target of reaching net zero emissions in the electricity sector by 2035 and in the economy more broadly by 2050. While governments across Canada have made significant progress toward these goals, significant gaps remain—especially regarding how policies are applied in the electricity sector. Federal climate policy in the electricity sector (in particular, the output-based treatment of electricity under federal carbon pricing) does not provide sufficient incentives for non-emitting generation and has weak incentives to ramp down use of unabated natural gas-fired electricity. It also does not rule out the construction of new gas-fired capacity,

which would risk becoming a stranded asset and could put climate targets out of reach.

2. **Creating resilient electricity systems aligned with net zero could put upward pressure on electricity rates.** While rising expenditure on electricity would be offset by falling expenditures on other types of energy, electricity rates might still increase in some regions under some scenarios (see *Figure G*).

FIGURE G.



Electricity rates might modestly increase—or even decline—given the decreasing costs of renewables and storage. But in some regions, in some scenarios, rates could increase more significantly as Canada modernizes its electricity systems. Smart policy can mitigate these potential rate increases and help keep electricity affordable for Canadians.

Sources: Dion et al. (2021); Dolter, Winter, and Guertin (2022).

This risk raises a number of concerns. Higher rates may disproportionately impact lower-income ratepayers, potentially exacerbating energy poverty. Investment costs may be unevenly distributed across regions, with residents in provinces and territories that rely on fossil fuel generation experiencing higher rate increases. Higher rates could also undermine the economic case for end-use electrification, which is critical to achieving net zero. And, critically, rising rates could undermine public and political support for the broader net zero transition. For these reasons, proactively mitigating potential upward pressure on rates can support a smooth net zero transition.

3. **Provincial and territorial policies and institutions are not sufficiently coordinated with net zero**. To align electricity systems with net zero goals, provincial and territorial policies and institutions—including regulators, system operators, and public utilities—must be coordinated with this goal. Yet, their mandates as they relate to climate change are often unstated or ambiguous and can be interpreted as being at odds with net zero investments. The most direct way to address this would be for federal, provincial, and territorial governments to provide greater policy certainty to 2050. However, gaps between existing policy and long-term goals are likely to persist. This poses a significant challenge, as regulators and other provincial institutions are not in a position to make assumptions or decisions about governments' future climate policy.

4. **Incentives for interregional coordination and interties are weak**. In Canada's decentralized federation, electricity systems are managed by provinces and territories, and there is no central governing authority. While enhanced integration and coordination between neighbouring electricity systems represents a cost-effective path to aligning Canada's electricity systems with net zero, systems remain largely siloed. In addition, a number of formal and informal barriers to integration exist in provinces and territories, including policies that limit or disincentivize interregional integration and trade, institutional cultures that undervalue coordination, and simple inertia.

3.2 *Recommendations for building electric federalism*

To address these four challenges, both federal and provincial/territorial orders of government have policy levers they can pull. Addressing the full set of challenges and successfully aligning Canadian electricity systems with net zero requires policy to be implemented by both of these orders of government, ideally in a coordinated way.

We have identified five key recommendations for how provincial, territorial, and federal governments can apply their respective policy levers to transform Canadian electricity systems. These recommendations are discussed in more detail in the *Electric Federalism report*.

A. The federal government should strengthen climate policies in the electricity sector

First, the federal government should strengthen federal carbon pricing policy by doing away with the output-based pricing system in the electricity sector and returning all carbon price revenues from electricity to provincial and territorial ratepayers. This approach would strengthen emissions reduction incentives while both protecting consumers and avoiding large interprovincial transfers.

Second, the federal government should employ a clean electricity standard alongside strengthened carbon pricing to support the switch to non-emitting electricity sources and ensure delivery on the 2035 net zero target. Such a standard should rule out construction of new gas-fired capacity and ensure that all generation is net zero as of 2035, while still letting market incentives from carbon pricing play a driving role in delivering cost-effective emissions reductions.

B. Federal, provincial, and territorial governments should leverage public funds to defray the costs of electricity system investments for ratepayers

The real or perceived risks of rising electricity rates could create challenges for electricity system transformations and the larger net zero transition. To mitigate these risks, federal, provincial, and territorial governments should use funds from their respective tax bases to defray the costs of electricity system investments for ratepayers.

Governments could provide support that would defray rate pressures in general, as well as in targeted ways that reduce costs for households experiencing, or at risk of, energy poverty.

Governments can provide these supports in a number of ways. For example, they could fund research, development, and demonstration projects; provide tax credits; co-fund large projects or infrastructure; or simply provide support directly to ratepayers. Providing subsidies can have pitfalls, particularly when they are not targeted at a clear market barrier (Ragan et al. 2017). But these challenges can be avoided when subsidies are coupled with the governance reforms in our next recommendation, which would help ensure investments defray costs for ratepayers in ways that are future-focused and cost-effective.

There are strong arguments to support government investment in electricity systems. First, since investments targeting emissions reductions benefit society broadly rather than just ratepayers alone, there is a case for sharing the costs more broadly as well. Second, governments are investing in a type of critical public infrastructure that will only grow in importance in a low-carbon world. And third, tax systems tend to be more progressive than ratepayer cost recovery, offering a fairer way of bearing investment costs. In addition, federal investment can provide an equalizing function, where provinces and territories that face the most costly transitions see greater benefits from federal support.

C. Provincial and territorial governments should flex their policy muscles to drive transformation of their electricity systems

Provincial and territorial governments can take considerable leadership in transforming their electricity systems, since they control many of the key policy levers. First, provinces and territories should implement their own carbon pricing policies and performance standards through equivalency agreements, so that they can implement policy that makes sense within their unique regional context. Second, they should issue directives and legislation mandating that regulators, public utilities, and system operators pursue climate goals. Third, to enable these actors to fulfil their updated mandates, provincial and territorial governments should develop comprehensive energy plans and commission independent pathway assessments to guide their work. Finally, provincial and territorial governments should remove or address formal and informal barriers to integration, including self-sufficiency mandates, policies that disincentivize interregional integration and trade, and institutional culture and inertia.

D. Both orders of government should pursue greater coordination and integration using their respective policy tools

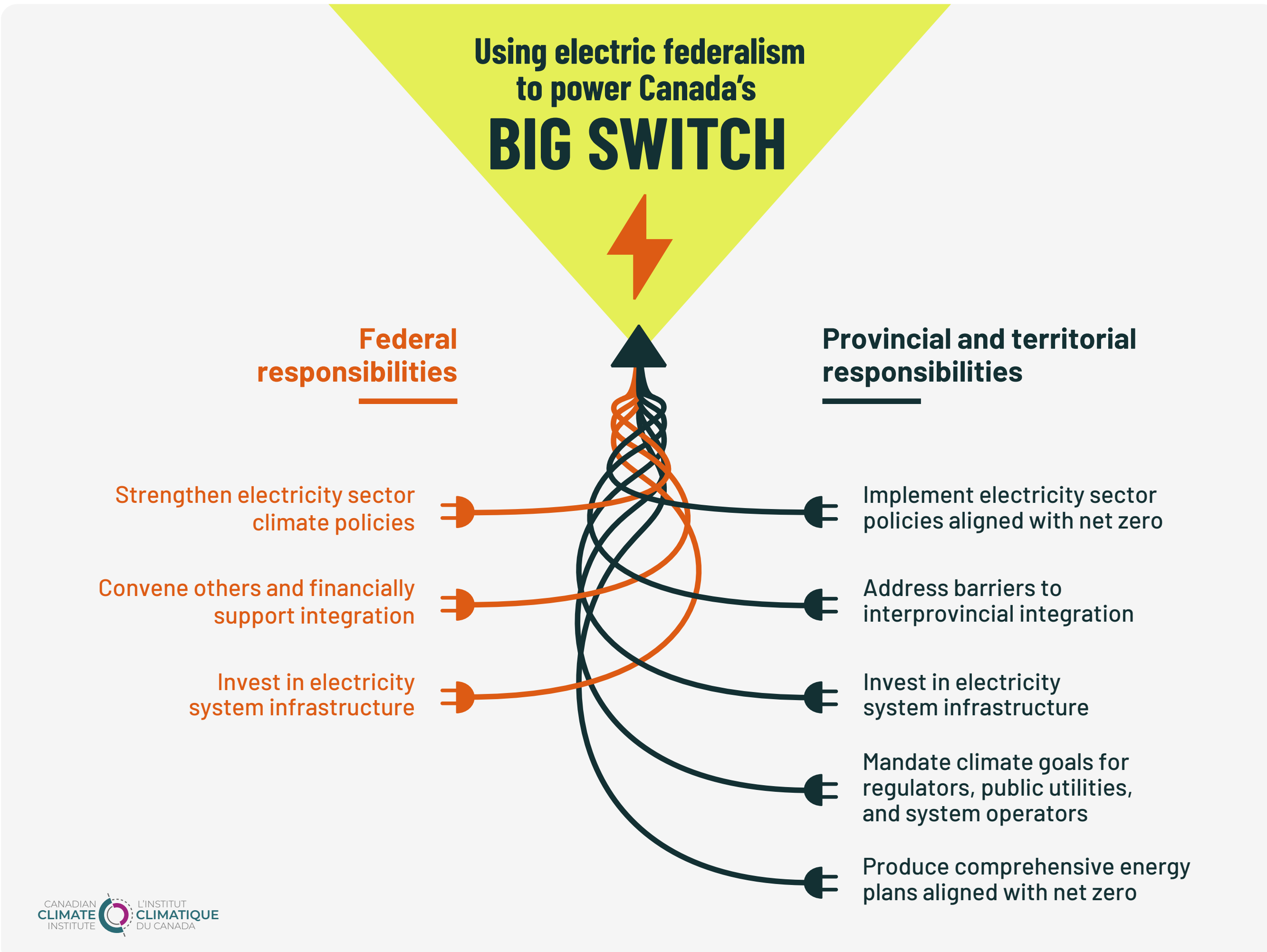
Nordic countries have successfully pursued greater coordination and integration of their electricity markets (McCarthy 2022). Canadian provinces and territories should similarly work bilaterally and multilaterally to integrate their electricity sectors, both by removing formal and informal barriers to integration and through new projects or planning initiatives. The federal government, for its part, should leverage its spending and convening powers—including the proposed Pan-Canadian Grid Council—to encourage greater coordination and integration of provincial and territorial systems.

Federal climate policies can help motivate greater integration, and federal convening and financial support can help incentivize it. But, ultimately, it is up to provinces and territories how much they choose to coordinate and integrate with their neighbours. As we discussed above, integration offers a cost-effective pathway for aligning Canadian electricity systems with net zero, so provinces should work to tap its considerable—and shared—benefits.

3.3 *Tying provincial, territorial, and federal actions together*

Our research finds that meaningful policy action across the four challenges requires *electric federalism*: coherent policy action from federal, provincial, and territorial governments that is capable of driving Canadian electricity systems toward alignment with net zero (see *Figure H*).

FIGURE H.



While there is a path forward where each order of government acts independently within its respective jurisdiction to implement the recommendations above, relying on the uncoordinated, independent initiative of each order of government means some critical policy actions might be slow to materialize. This risks putting the achievement of broader, longer-term climate targets in jeopardy, since resilient, cost-effective, non-emitting electricity systems are essential for enabling energy end-use electrification—a central component of every possible pathway to reaching net zero emissions (Dion et al. 2021).

Below, we discuss a potential coordinated approach that sees the federal government supporting and accelerating change while also respecting provincial and territorial jurisdiction over electricity.

E. The federal government should consider offering sustained, predictable financial support to provinces and territories to accelerate electricity system transformations, in exchange for certain high-level conditions being met

Such agreements would attach a limited number of high-level conditions to this potential financial support that tie together many of the recommendations above. These conditions include:

- updating the mandates of key provincial and territorial institutions,
- developing comprehensive energy plans and independent pathway assessments, and
- participating in inter-jurisdictional working groups, such as the proposed Grid Council.

Federal support would be conditional on provinces and territories developing these specific policies, plans, and assessments, but their content would be entirely at those governments' discretion. As long as such efforts were focused on developing a net zero energy system in the province or territory and provided sufficient detail, the federal government would leave provincial and territorial governments and institutions to determine *how* they envision their electricity systems aligning with net zero. With the above conditions in place, federal support would not have to be tied to any particular investment type, technology, or measure, but only to electricity system investment in general.

Provinces and territories, for their part, would have access to—and control over—federal funds that could help reduce pressure (or perceived pressure) on electricity rates. This is a significant benefit that could greatly facilitate electricity sector transformation. Without it, pressure from households and businesses to keep electricity affordable could risk delaying the provincial and territorial policy changes and investments required to modernize electricity systems and align them with net zero.

This kind of approach can offer a way for the federal government to enable and accelerate the transformation of provincial and territorial electricity systems in line with net zero, and in a way that makes sense in the Canadian federation. If the federal government is serious about achieving net zero in the electricity sector by 2035 and in the economy as a whole by 2050, it should begin exploring this approach immediately and consider making it a key plank of its Budget 2023.

ANNEX

Stakeholder consultations

We wish to acknowledge the input and guidance we received during our engagement with a broad range of stakeholders, including:

Alberta Innovates
Alberta Utilities Commission
Algonquin Power & Utilities Corp.
AltaLink
Asia Pacific Economic Corporation
Association of Municipalities of Ontario
Association québécoise pour l'énegie renouvelable
ATCO
Atlantic Canada Opportunities Agency
Atlantic Chamber of Commerce
Atlantic Policy Congress of First Nations Chiefs Secretariat
Atlantic Provinces Economic Council
Atlantica Center for Energy
Baffin Regional Chamber of Commerce
BC Hydro
British Columbia Utilities Commission
Business Council of British Columbia
C.D. Howe Institute
CAMPUT: Canada's Utility and Energy Regulators
Canada Energy Regulator
Canada Grid
Canadian German Chamber of Industry and Commerce
Canadian Nuclear Association
Canadian Renewable Energy Association
Capital Power Corporation
Charlottetown Chamber of Commerce
City of Charlottetown
City of Halifax
City of Medicine Hat
City of Saskatoon
City of St. John's
City of Toronto
City of Vancouver
City of Winnipeg
Clean Energy BC
Clean Energy Canada
Clean Foundation
Climate Change Connection
Community Energy Association
Conboy Advisory Services
Council of Yukon First Nations
Counsel Public Affairs
Cowesses Ventures
David Suzuki Foundation
Delphi Group
Dunsky Energy Consulting
Ecology Action Centre
Ecotrust Canada
Efficiency Canada
Efficiency One
Electric Power Research Institute
Electricity Canada
Emissions Reduction Alberta
Energy and Materials Research Group at Simon Fraser University
ENMAX
ESMIA Consultants
Environment and Climate Change Canada
Federation of Prince Edward Island Municipalities
First Nations Power Authority
Fortis BC
General Electric Canada
Government of Alberta
Government of British Columbia
Government of Manitoba
Government of New Brunswick
Government of Newfoundland and Labrador
Government of Northwest Territories
Government of Nova Scotia
Government of Nunavut
Government of Ontario
Government of Prince Edward Island
Government of Quebec
Government of Saskatchewan
Government of Yukon
Greengate Power
Heartland Generation
Heritage Gas
Hydro One
Hydro Quebec

International Institute for Sustainable Development
Indigenous Clean Energy
Industrial Gas Users Association
Island Regulatory and Appeals Commission
Kanaka Bar Indian Band
Keppel Gate Consulting
Kisik Clean Energy
Kolesar Buchanan & Associates Ltd.
Manitoba Environmental Industries Association
Manitoba Hydro
Manitoba Public Utilities Board
Maritime Electric Company
Maritimes Energy Association
Metro Vancouver
Nunastsiavut Government
Nalcor
National Farmers Union - Region 6
Natural Forces
Natural Resources Canada
Navius Research
NB Power
New Brunswick Energy and Utilities Board
New Brunswick Energy Marketing Corporation
New Relationship Trust
Newfoundland and Labrador Board of Commissioners
Newfoundland and Labrador Environmental Industry Association
Newfoundland Power
Newfoundland and Labrador Hydro
Northwest Territories Association of Communities
Northland Power
Northwest Territories Power Corporation
Nova Scotia Power
Nova Scotia Utility and Review Board
NS Power
NS Utility & Review Board
Ofgem
Ontario Chamber of Commerce
Opportunities New Brunswick
Ontario Energy Board
Ontario Power Generation
Opportunities New Brunswick
Pacific Institute for Climate Solutions
PEI Energy Corporation
Pembina Institute
Polaris Strategy + Insight
Power Advisory LLC
Powerconsumer Inc.
Prairie Climate Centre
Propulsion Quebec
Qikiqtaaluk Corporation
Qikiqtani Inuit Association
Quebec Business Council on the Environment
Quebec Net Positive
QUEST
Régie de l'énergie du Québec
Region of Durham
Reshape Infrastructure Strategies
Rural Municipalities of Alberta
Saint John Energy
SaskPower
Saskatchewan Chamber of Commerce
Saskatchewan Environmental Society
Saskatchewan Urban Municipalities Association
Saskatoon Light and Power
Saskatchewan Rate and Review Panel
Sawridge First Nation
Smart Grid Innovation Network
Sustainable Energy Systems Integration & Transitions Group
Sustainable Waterloo Region
Toronto and Region Board of Trade
Toronto and Region Conservation Authority
Toronto Atmospheric Fund
Town of Canmore
Town of Digby
TransAlta
Transition Accelerator
Trottier Energy Institute
Toronto and Region Conservation Authority
Toronto Hydro
Waterpower Canada
Wind Energy Institute of Canada
Wrangellia Consulting

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Acknowledgments

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THE BIG SWITCH

POWERING CANADA'S NET ZERO FUTURE

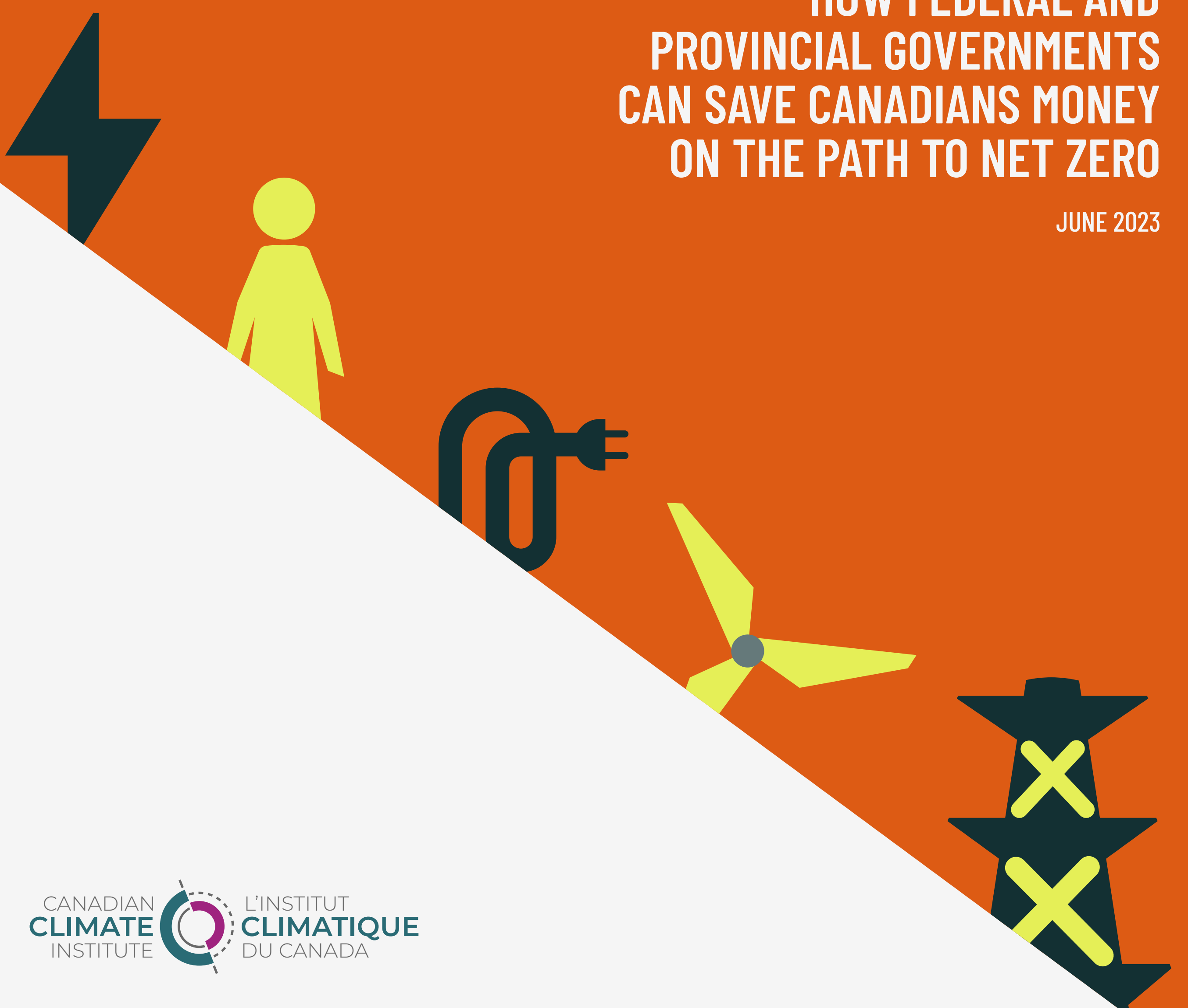
MAY 2022

CANADIAN CLIMATE INSTITUTE
L'INSTITUT CLIMATIQUE DU CANADA

CLEAN ELECTRICITY, AFFORDABLE ENERGY

HOW FEDERAL AND PROVINCIAL GOVERNMENTS CAN SAVE CANADIANS MONEY ON THE PATH TO NET ZERO

JUNE 2023



CANADIAN CLIMATE INSTITUTE
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01 *Introduction*

The federal government's *Budget 2023* included substantial new financial supports for provinces and territories to help expand clean electricity. By tapping into the tens of billions of dollars on the table, provinces and territories can pave the way towards an affordable energy future for Canadians by expanding their clean electricity systems.

Our research shows that as the country transitions to clean energy, average energy costs for Canadians will be 12 per cent lower in 2050 than today. Households will use more electricity in place of fossil fuels, as they switch to more efficient technologies like electric vehicles and heat pumps.

Electricity rates may rise gradually over time in this larger energy context. In response, provinces can develop policy tools that can help keep electricity affordable and ensure fairness for low- and medium-income households. Signing onto high-level conditions to access federal support will help provinces and territories realize this future.

Bigger, cleaner, smarter electricity systems are necessary if Canada is to make this transition and maintain its economic competitiveness. Clean electricity will be the foundation for emissions reductions in other sectors, as more activity is electrified over time. And businesses are increasingly demanding clean power as a necessary condition of their investment.

This report updates research from the Canadian Climate Institute's 2022 report, *The Big Switch*, which identified the scale of investment needed to get the country on a net zero emissions pathway. This analysis explores the potential benefits for provinces and territories of the latest federal fiscal support for clean electricity, and updates our projections of electricity rates from the *Big Switch*.

The federal government is offering provinces tens of billions in financial support for cleaner electricity systems.

Supports outlined in *federal Budget 2023* include:

- $3 billion over 13 years for renewable energy and electrical grid modernization projects through the Smart Renewables and Electrification Pathways (SREP) program.
- An estimated $25.7 billion between 2024 and 2035 is available through the Clean Electricity Investment Tax Credit (ITC), which applies a 15 per cent credit to an array of electricity generation and storage technologies and interties (with solar, wind, storage and small modular reactors built by taxed entities qualifying for 30 per cent under the Clean Technology Investment Tax Credit). Provincial uptake of the Clean Electricity ITC will be subject to high-level conditions that the federal government is still developing.
- At least $10 billion for clean power and an additional $10 billion for clean growth infrastructure is available in preferential financing from the Canada Infrastructure Bank, the federal government's primary investment financing vehicle for supporting clean electricity generation, transmission, and storage projects.

02 *Key Findings*

These supports represent an historic commitment to the clean energy transition. Our estimates in *Figure 1* show that all provinces stand to benefit. But in particular, provinces transitioning away from more emissions-intensive grids—Alberta, Saskatchewan, Nova Scotia and New Brunswick—stand to benefit the most relative to the scale of their existing grid infrastructure (receiving 33 per cent more funding than hydro-rich provinces per Gigawatt of presently installed capacity).

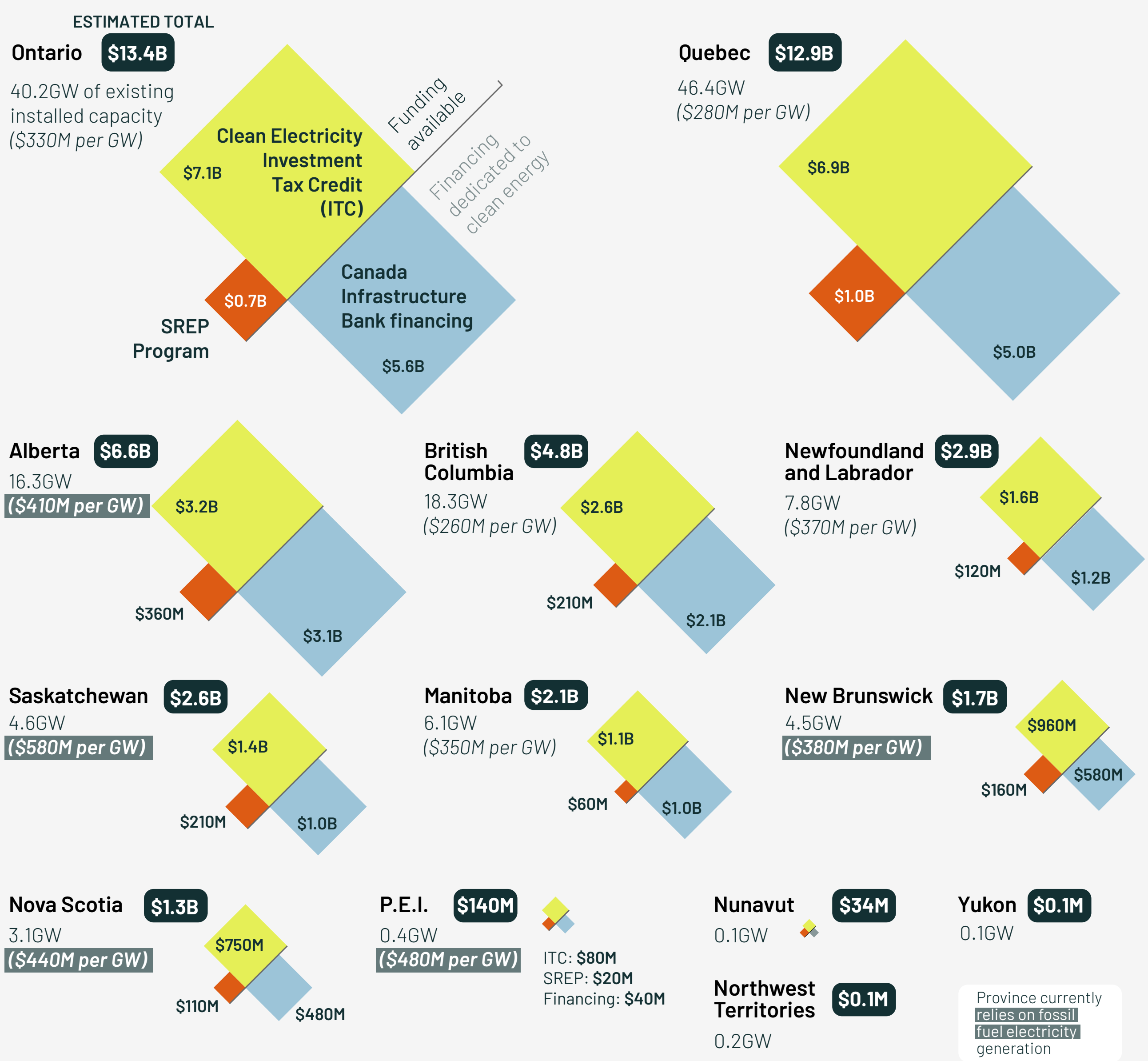
For example, Alberta could receive as much as $3.5 billion, in addition to $3 billion of financing support from the Canada Infrastructure Bank. Similarly, Saskatchewan could access more than $1.6 billion in direct support and over $1 billion in financing.

Provinces and territories accessing federal financial support by signing on to the high-level conditions attached to it will unlock direct benefits for their ratepayers. They would continue to retain control over how their grids decarbonize. And the funding and financing supports will reduce upward pressure on electricity rates that might otherwise occur as Canada makes the investments needed to modernize its aging grids and find efficiencies. It will help provinces build the bigger, cleaner electricity systems needed to support rising demand from electrification.

FIGURE 1.

Provinces can get billions of dollars in federal support for clean electricity

Those that currently rely on fossil fuels for electricity will receive **more support** to build a bigger, cleaner grid.



Through the energy transition, households will consume more electricity and at slightly higher rates over time, but spend less on fuel and on home heating bills as they switch from vehicles and appliances that run on fossil fuels to electric vehicles and heat pumps. These technologies are significantly more efficient than fossil fuel alternatives at meeting our needs—so even if electricity rates go up, energy spending will drop.

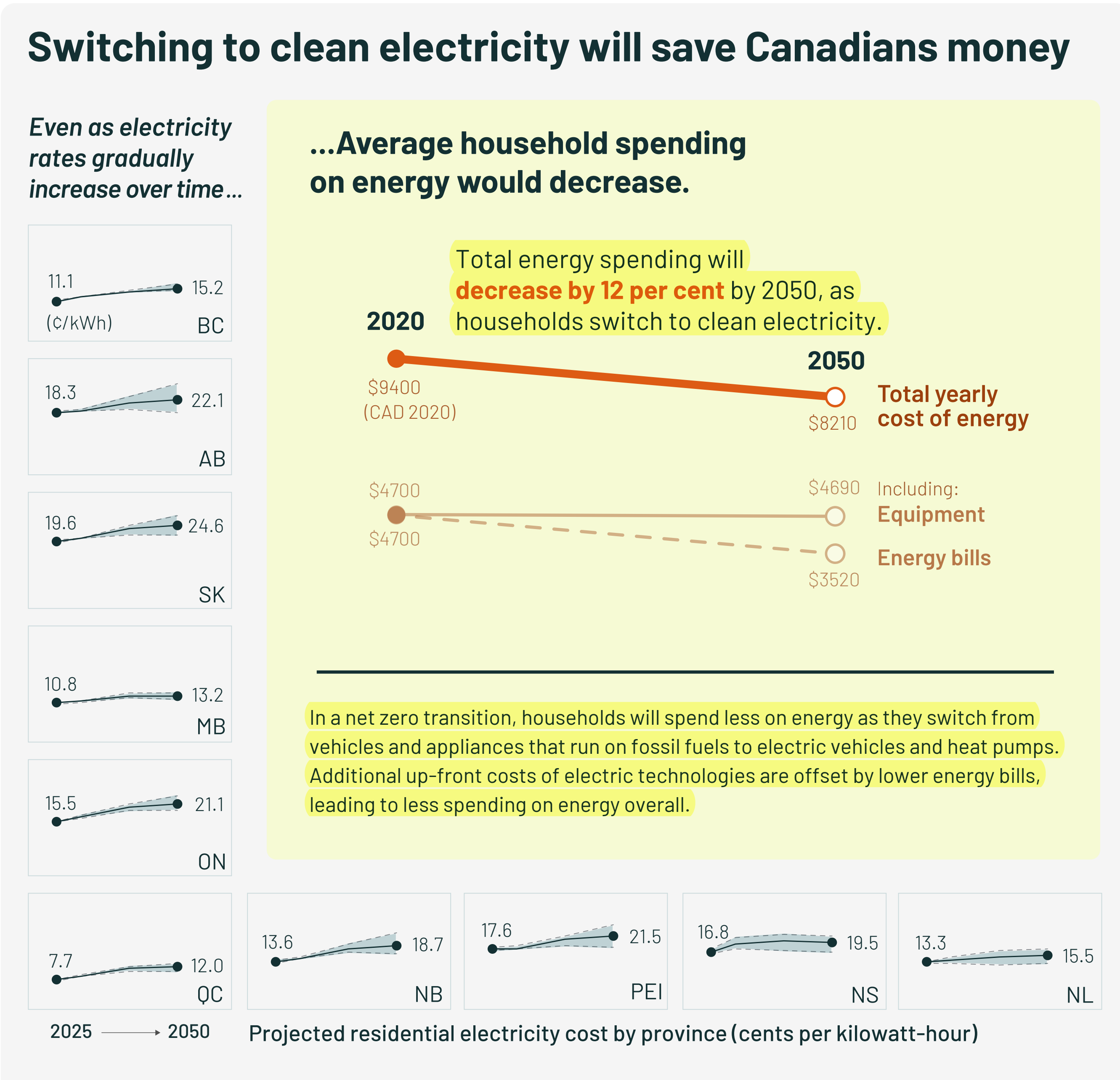
Energy bills will also be less volatile as households transition from fossil fuels to electricity. For example, electrification of transportation and space heating can help protect Canadians from price spikes in fossil fuels and wider associated price inflation. In September 2022, the price of energy was over 40 per cent higher in Europe than a year before, because of Russia's invasion of Ukraine. The United Kingdom's wholesale electricity price quadrupled, with the cost of fossil gas responsible for 85 per cent of this spike (*Brown, 2022*). The war, and the energy volatility it has driven has only increased Europe's resolve and efforts to move to a renewable energy system (*European Commission, 2022*).

For an average Canadian, ongoing cost savings across all forms of energy consumed will generally offset higher upfront costs for electric equipment—and these upfront costs will themselves fall over time, as our production and use of this equipment scales. Average household energy spending—on energy bills and the equipment that that energy powers—will decrease by 12 per cent between now and 2050 under a net zero transition.

While electricity prices are expected to modestly rise in most provinces to 2050, utility rates are designed to spread investment costs over time, which lessens impacts on affordability. The exact impact on rates will vary by province, but can be anticipated. Our updated rate modelling in *Figure 2* provides a picture of what kind of rate increases provinces can expect.[1]

1. Because the design of the federal Clean Electricity Regulation is still pending, the rates we show above don't necessarily fully reflect its impacts. While some of the underlying modeling studies proxy its likely effects, others model a more gradual pace for grid decarbonization. This means that, in practice, meeting the goal of net zero electricity by 2035 could shift some of the needed investment and corresponding rate increases forward relative to what's seen in the figure. At the same time, this would mean that support from the federal government under the Clean Electricity Investment Tax Credits (which sunset in 2035) would increase, mitigating the impact on rates.

FIGURE 2.


Switching to clean electricity will save Canadians money
Even as electricity rates gradually increase over time...
11.1
15.2
(¢/kWh)
BC
18.3
22.1
AB
19.6
24.6
SK
10.8
13.2
MB
15.5
21.1
ON
7.7
12.0
QC
13.6
18.7
NB
17.6
21.5
PEI
16.8
19.5
NS
13.3
15.5
NL
2025 → 2050
Projected residential electricity cost by province (cents per kilowatt-hour)
...Average household spending on energy would decrease.
Total energy spending will decrease by 12 per cent by 2050, as households switch to clean electricity.
2020
2050
$9400 (CAD 2020)
$8210
Total yearly cost of energy
$4700
$4690
Including:
Equipment
$4700
Energy bills
$3520
In a net zero transition, households will spend less on energy as they switch from vehicles and appliances that run on fossil fuels to electric vehicles and heat pumps. Additional up-front costs of electric technologies are offset by lower energy bills, leading to less spending on energy overall.

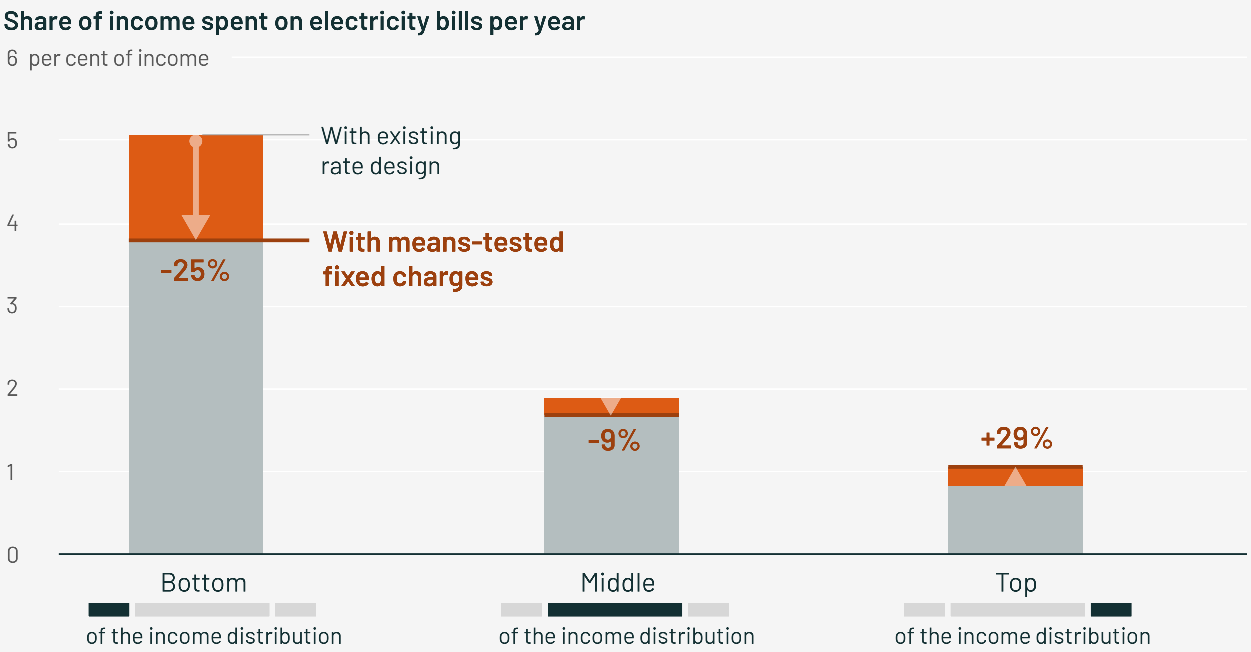
Even though future electricity rate increases are expected to be modest in Canada—especially in the context of lower overall energy costs—not all households will see the same benefit. Lower-income households, for example, face obstacles to participating in energy efficiency programs and are less likely to benefit from savings at the gas pump due to lower rates of vehicle ownership. Existing rate structures are also likely to exacerbate inequities in the energy transition (*Dolter & Winter, 2022*). Provinces can reduce disproportionate impacts on low-income households by targeting supports to where they are most needed.

Provincial governments have policy options to improve fairness for low- and middle-income households facing potential electricity bill increases. Targeted support and innovative rate design can help ensure affordability for all. For example, utilities often use fixed charges to recoup some of the costs of electricity transmission and distribution infrastructure. These fixed charges could be modified to vary based either on income (as proposed by utilities in California) or by peak electricity demand from a household (higher-income households tend to have higher peak energy demand). These options have not yet been implemented in Canada. As *Figure 3* illustrates, this could result in improved fairness. Low-income households would particularly benefit, seeing savings that amount to 1.3 per cent of their average income. And while this benefit would be funded by higher charges for high-income households, these cost increases would only amount to only 0.2 per cent of their incomes.

FIGURE 3.

Provinces can make energy more affordable

Targeted policy solutions, like means-tested fixed charges, help keep electricity bills fair and affordable for low- and middle-income households.



03 *Conclusion*

Tens of billions of dollars in federal support are available for provinces and territories ready to build bigger, cleaner, smarter electricity grids. Provinces and territories should sign on to the conditions for this support in order to unlock its benefits for ratepayers. Significant investments will be required to modernize electricity infrastructure across Canada and ensure it is ready to supply reliable and affordable power in a net zero future. These necessary upgrades will likely lead to modest increases in electricity rates in the decades ahead, but the federal support available will help keep costs down.

Further, Canadian consumers will be insulated from the effects of potential electricity rate increases because overall energy spending will drop as households switch from fossil fuel technologies to more efficient and cleaner electrical alternatives. While average Canadians will benefit from these substantial savings on energy bills, provinces and territories should use targeted policy action to keep electricity affordable for those on lower and middle incomes.

Federal government support combined with provincial government policy actions can and should unlock an affordable energy future for Canadians.

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Methods

Distribution of federal funding

Figure 1: The allocation of federal funding and financing commitments among provinces and territories is based on the anticipated investment in generation capacity within each jurisdiction (in terms of technology, scale and timing). We estimate this anticipated investment by averaging findings across three of the electricity modeling studies profiled in our 2022 report *The Big Switch*: EPRI 2021, CER 2021, and IET 2021 (for a breakdown of the assumptions and findings of these studies, see the Annex of our 2022 report *Bigger, Cleaner, Smarter*). The resulting chart shows cumulative funding and financial support by province or territory to 2035. Total funding for each program stream reflects estimates and allocations from the 2023 federal budget.

Updated rates analysis

Figure 2: This figure updates our rates analysis from *The Big Switch*. For further details on methodology see (*Dolter & Winter 2022*). Updates to our previous analysis and methods include:

- Accounting for electricity-focused funding estimates and allocations announced in the 2023 budget.
- Changing 2023 rate values (the starting point in this analysis) to reflect current rates in each province and inflating to 2023 dollars.
- Investment costs are apportioned across users contemporaneously and over time, and funded primarily by debt. Modelling of rates therefore requires understanding of existing as well as future potential debt. Our latest analysis updates existing debt assumptions, particularly for Newfoundland and Labrador.
- Model-specific calculations are now used to move from utility average costs to average consumer prices.

Affordability analysis

Figure 2: Analysis presented here is based on modelling results from our report, *Canada's Net Zero Future*, which modelled 62 scenarios that achieve net zero emission targets in Canada. Model outputs include total annual energy expenditures across all scenarios by income quintile. Expenditures are expressed in terms of energy bills (or amount paid for energy consumption) and annualized equipment cost, such as household energy appliances and vehicles. The annualized equipment cost excludes any homeowner subsidy programs.

Since the model outputs 62 projections for energy expenditures, the scenario that projected the highest total energy expenditures by 2050 was selected as a representative, and most conservative scenario for this analysis. Total energy expenditures by income quintile were converted to expenditures per household using the underlying population projections.

The results of this analysis are shown in *Figure 2*, which represents the average household energy spending (energy expenditures) in 2020 to 2050 under the most conservative scenario. Numbers are presented in aggregate for the average Canadian household.

Targeted policy (Means-tested fixed charges)

Figure 3: The final analysis explores how regulators and utilities could change rate structures to address the issue of distributional equity and affordability for low and middle income households. We consider the impact of making fixed charges income-dependent (increasing with income) and compare results with the present flat fixed rate design. The fixed charges in the modelling match the progressivity of the federal personal income tax system. The work follows the methodology outlined in (*Dolter & Winter, 2022*) and uses the updated rates presented here.

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CLEAN ELECTRICITY, AFFORDABLE ENERGY

HOW FEDERAL AND PROVINCIAL GOVERNMENTS CAN SAVE CANADIANS MONEY ON THE PATH TO NET ZERO

CANADIAN CLIMATE INSTITUTE
L'INSTITUT CLIMATIQUE DU CANADA

Who We Are

We are Canada's leading climate change policy research organization, producing the rigorous analysis and evidence-based recommendations that are needed to advance climate resilience, chart net zero pathways, and drive long-term prosperity. The strength of our work is rooted in our independence, in the diversity and depth of our staff, board and advisors in fields from climate mitigation to adaptation and clean growth, and in the breadth of the stakeholders and rights holders we engage throug our research.

We are non-partisan, independently governed and a registered Canadian charity: *71860 4119 RR0001*.

The Canadian Climate Institute is a member of the **International Climate Councils Network (https://climatecouncilsnetwork.org/)** (ICCN), an organization that facilitates collaboration and mutual support betwee Climate Councils from around the world. We have also joined the Government of Canada's 50 – 30 Challenge (https://ised-isde.canada.ca/site/ised/en/50-30-challenge-your-diversity-advantage). The goal of the program is to challenge Canadian organizations to increase the representation and inclusion of diverse groups within their workplaces, while highlighting the benefits of giving all Canadians a seat at the table.

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Board of Directors

Expert Panels

Council of Advisors

Official Languages Policy

Justice and Equity Statement

Background

The Canadian Climate Institute was established following a competitive request for proposals (https://www.canada.ca/en/environment-climate-change/news/2018/10/government-of-canada-to-partner-with-independent-climate-experts-to-support-ambitious-action-on-clean-growth-and-climate-change.html) led by Environment and Climate Change Canada. That process resulted in a mandate to create a pan-Canadian expert collaboration (https://www.canada.ca/en/environment-climate-change/news/2019/04/the-pan-canadian-expert-collaboration.html) that would "provide independent and expert-driven analysis to help Canada move toward clean growth in all sectors and regions of the country." Our work is currently supported through a five-year contribution agreement with Environment and Climate Change Canada and a growing list of philanthropic funders. The Institute is an independent organization and retains full control over its research, findings, and policy recommendations.

Environment and Climate Change Canada   Environnement et Changement climatique Canada

The following organizations contributed to the development of the Canadian Climate Institute:

- ACT (the Adaptation to Climate Change Team), SFU (http://act-adapt.org/)
- Alberta Innovates (https://albertainnovates.ca/)
- Canada's Ecofiscal Commission (https://ecofiscal.ca/)
- Canadian Energy Systems Analysis Research (CESAR) (https://www.cesarnet.ca/)
- Centre for Indigenous Environmental Resources (CIER) (http://www.yourcier.org/)
- Evergreen (https://www.evergreen.ca/)
- Foundation for Environmental Stewardship (FES) (https://www.fesplanet.org/)
- Intact Centre on Climate Adaptation (https://www.intactcentreclimateadaptation.ca/)
- L'Institut de l'énergie Trottier (IET) (http://iet.polymtl.ca/)
- Interdisciplinary Centre on Climate Change (https://uwaterloo.ca/climate-centre/)
- Ivey Foundation (https://www.ivey.org/)
- Labrador Institute (https://www.mun.ca/labradorinstitute/)
- MaRS Discovery District (https://www.marsdd.com/)
- McConnell Foundation (https://mcconnellfoundation.ca)
- National Consortium for Indigenous Economic Development (https://www.uvic.ca/ncied/)
- Northern Climate ExChange, Yukon College (https://www.yukoncollege.yk.ca/research/our-research/northern-climate exchange)
- Ouranos (https://www.ouranos.ca/en/)
- Pacific Institute for Climate Solutions (PICS) (https://pics.uvic.ca/)
- Prairie Climate Centre (http://prairieclimatecentre.ca/)
- Smart Prosperity Institute (https://institute.smartprosperity.ca/)
- SWITCH (L'Alliance pour une économie verte au Québec) (https://allianceswitch.ca/en/)
- Trottier Family Foundation (https://www.trottierfoundation.com/)
- World Resources Institute (WRI) (https://www.wri.org/)

Public Contributions Policy Statement

1. The Canadian Climate Institute is a registered charity dedicated to climate change research and education.
2. Individuals and organizations such as governments, trade unions, and non-profit or for-profit businesses are all welcome to financially contribute to the Canadian Climate Institute.
3. In accepting a contribution, the Canadian Climate Institute will seek to ensure that the donor's objectives are compatibl with our mission, vision, values, and programming.
4. The Canadian Climate Institute reserves the right to refuse a contribution that is not compatible with the above criteria or for any other reason.
5. Donor names will be publicly available, but all donor personal information is confidential and will not be traded or sold.

The Pan-Canadian Expert Collaboration

From: Environment and Climate Change Canada

Backgrounder

The Pan-Canadian Expert Collaboration is a new group representing more than 15 diverse and reputable organizations across Canada, which have extensive experience in the clean growth and climate change fields.

The Pan-Canadian Expert Collaboration will establish an institute that will

- provide credible and authoritative advice to Canadians and their governments;
- develop and provide independent and expert-driven analysis to help Canada move toward clean growth in all sectors and regions of the country;
- develop advice and analysis spanning climate change mitigation, adaptation, and clean growth;
- set its own agenda and operate independently from government; and
- fill existing information gaps and help translate research into useful information for policy decision-making.

While the institute is an independent, stand-alone organization, the following partners will work closely with the institute to achieve its objectives:

- Adaptation to Climate Change Team, Simon Fraser University

- Alberta Innovates
- Canada’s Ecofiscal Commission
- Canadian Energy Systems Analysis Research, University of Calgary
- Centre for Indigenous Environmental Resources
- Evergreen and Future Cities Canada
- Foundation for Environmental Stewardship
- Institut de l’énergie Trottier, Polytechnique Montréal
- Intact Centre on Climate Adaptation and the Interdisciplinary Centre on Climate Change, University of Waterloo
- Ivey Foundation
- Labrador Institute, Memorial University
- MaRS Discovery District
- National Consortium for Indigenous Economic Development, University of Victoria
- Ouranos
- Pacific Institute for Climate Solutions, University of Victoria
- Prairie Climate Centre, University of Winnipeg
- Smart Prosperity Institute
- Switch (l’Alliance pour une économie verte au Québec)
- Trottier Family Foundation
- World Resources Institute
- Yukon College

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2030 Emissions Reduction Plan – Canada's Next Steps for Clean Air and a Strong Economy

From: Environment and Climate Change Canada

Backgrounder

On climate change, the science is clear—we must take action now to protect our planet and secure our children's future. But the economics are clear too: to build a strong, resilient economy for generations to come, we must harness the power of a cleaner future.

Canada's average temperatures are rising at twice the global average, and three times in the North. Polluting less and taking steps to remove excess carbon from the air will be one of the most important undertakings in Canada's history. Last year, Canada increased its ambition on climate change under the Paris Agreement. The 2030 Emissions Reduction Plan describes the many actions that are already driving significant reductions as well as the new measures that will ensure that we reduce emissions across the entire economy to reach our emissions reduction target of 40 to 45 percent below 2005 levels by 2030 and put us on a path to achieve net-zero emissions by 2050.

Reaching our climate goals will also help ensure that the conditions are right to seize the growing economic opportunities of a clean future. This Plan includes $9.1 billion in new investments, and reflects economy-wide measures such as carbon pricing and clean fuels, while also targeting actions sector by sector ranging from buildings to vehicles to industry and agriculture. These measures will drive reductions while creating jobs for workers and opportunities for businesses. The Government of Canada is working with Canadians in all parts of the country and all sectors of the economy to achieve Canada's climate goals and seize new economic opportunities.

In developing the 2030 Emissions Reduction Plan, we heard from over 30,000 Canadians—young people, workers, Indigenous Peoples, business owners, and more. Their key message to the Government of Canada is that climate action must go hand in hand with keeping life affordable for Canadians and creating good jobs. This plan reflects that vision.

The 2030 plan is designed to be evergreen—a comprehensive roadmap that reflects levels of ambition to guide emissions reduction efforts in each sector. As governments, businesses, non-profits, and communities across the country work together to reach these targets, we will identify and respond to new opportunities.

This is the first Emissions Reduction Plan issued under the *Canadian Net-Zero Emissions Accountability Act*. Progress under the plan will be reviewed in progress reports produced in 2023, 2025, and 2027. Additional targets and plans will be developed for 2035 through to 2050.

Publishing this Plan fulfills a requirement under the *Act*, and presents Canada's bold next steps forward as we keep our air clean and build a strong economy for everyone.

In the 2030 plan, the Government of Canada is taking action by:

Helping to reduce energy costs for our homes and buildings, while driving down emissions to net zero by 2050 and boosting climate resiliency through the development of the $150-million Canada Green Buildings Strategy. Working with provinces, territories, and other partners, the strategy will build off existing initiatives and set out new policy, programs, incentives, and standards needed to drive a massive retrofit of the existing building stock, and construction to the highest zero-carbon standards. Under the 2030 Emissions Reduction Plan, the Canada Greener Homes Loan program will receive an additional investment of $458.5 million. Together, these measures and others outlined in the 2030 Emissions Reduction Plan, will help Canadians reduce emissions, save money on renovations and heating and cooling costs, and stimulate well-paying jobs in the economy.

Empowering communities to take climate action by expanding the Low Carbon Economy Fund through a $2.2-billion renewal. The funding aims to leverage further climate actions from provinces and territories, municipalities, universities, colleges, schools, hospitals, businesses, not-for-profit organizations, and Indigenous communities and organizations. The renewed Low Carbon Economy Fund will also support climate action by Indigenous Peoples with a new $180-million Indigenous Leadership Fund. This will support clean energy and energy efficiency projects led by First Nations, Inuit, and Métis communities and organizations. In addition, the Government of Canada will support regional growth opportunities and energy systems transformation through a $25-million investment in Regional Strategic Initiatives that will drive economic prosperity and the creation of sustainable jobs in a net-zero economy.

Making it easier for Canadians to switch to electric vehicles through additional funding of $400 million for zero-emission vehicles (ZEVs) charging stations, in support of the Government's objective of adding 50,000 ZEV chargers to Canada's network. In addition, the Canada Infrastructure Bank will also invest $500 million in ZEV charging and refueling infrastructure. The Government of Canada will provide $1.7 billion to extend the Incentives for Zero-Emission Vehicles (iZEV) program will make it more affordable and easier for Canadians to buy and drive new electric light-duty vehicles. The Government will also put in place a sales mandate to ensure at least 20 percent of new light-duty vehicle sales will be zero-emission vehicles by 2026, at least 60 percent by 2030 and 100 percent by 2035. To reduce emissions from medium- and heavy-duty vehicles (MHDVs), the Government of Canada will aim to achieve 35 percent of total MHDV sales being ZEVs by 2030. In addition, the Government will develop a MHDV ZEV regulation to require 100 percent MHDV sales to be ZEVs by 2040 for a subset of vehicle types based on feasibility, with interim 2030 regulated sales requirements that would vary for different vehicle categories based on feasibility, and explore interim targets for the mid-2020s.

Driving down carbon pollution from the oil and gas sector. The International Energy Agency's Net-Zero Scenario sees continued oil and gas use globally, but with demand declining significantly in the coming decades. Competing in this future means not only diversifying our energy mix, but also offering lower carbon oil and gas to the world. The Plan presents modelling of the most economically efficient pathway to meeting Canada's 2030 target. Drawing on that modelling, the Plan includes a projected contribution from the oil and gas sector of emission reductions to 31 percent below 2005 levels in 2030 (or to 42 percent below 2019 levels). This will guide the Government of Canada's work with industry, provinces, Indigenous partners, and civil society to define and implement the cap on oil and gas sector emissions. Following consultations, the cap will be designed to lower emissions at a pace and scale needed to achieve net zero by 2050. The government is also working to reduce oil and gas methane by at least 75 percent by 2030, supporting clean technologies to further decarbonize the sector, and working to create sustainable jobs.

Powering the economy with renewable electricity. Electrifying more activities—from vehicles to heating and cooling buildings to various industrial processes—will be needed for Canada to transition to net-zero emissions by 2050. To do that, Canada needs to both increase the supply of electricity and ensure that all electricity generation has net-zero emissions. While Canada already has one of the cleanest electricity grids in the world, with over 80 percent produced by non-emitting sources, transitioning the remaining generation to clean sources will reduce greenhouse gas (GHG) emissions, improve local air quality, and create jobs and economic growth with the construction of new power sources and retrofitting and fuel-switching existing power plants and buildings. To ensure success, the Government of Canada will work with provinces and utilities to establish a Pan-Canadian Grid Council to promote clean electricity infrastructure investments. Additionally, the Government of Canada will invest an additional $600 million in the Smart Renewables and Electrification Pathways Program to support renewable electricity and grid modernization projects and $250 million to support predevelopment work for large clean electricity projects, in collaboration with provinces.

Helping industries develop and adopt clean technology in their journey to net-zero emissions. Canada is positioning its industries to be green and competitive. This includes developing a carbon capture, utilization, and storage (CCUS) strategy; introducing an investment tax credit to incentivize the development and adoption of this important technology; and investing $194 million to expand the Industrial Energy Management System to support ISO 50001 certification, energy managers, cohort-based training, audits, and energy efficiency–focused retrofits for key small-to-moderate projects.

Investing in nature and natural climate solutions with an additional $780 million for the Nature Smart Climate Solutions Fund to deliver additional emission reductions from nature-based climate solutions. The Fund supports projects that conserve, restore, and enhance Canada’s vast and globally significant endowment of wetlands, peatlands, and grasslands to store and capture carbon. To stimulate demand for other projects across Canada that reduce GHG emissions, sequester carbon, and generate economic opportunities, Canada will continue to develop protocols under the Federal GHG Offset System, including for projects that focus on nature-based climate solutions.

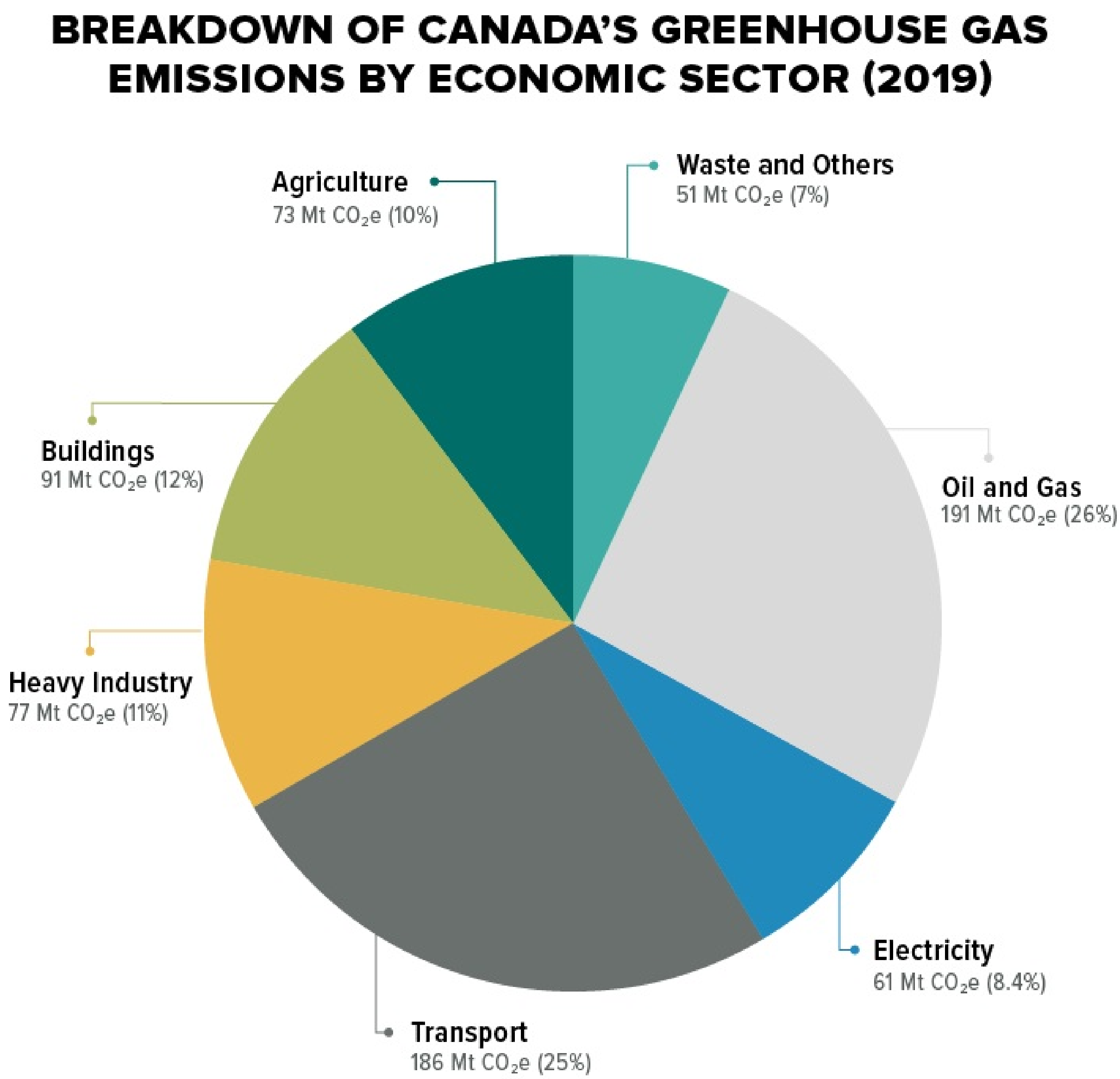
Supporting farmers as partners in building a clean, prosperous future. Farmers are key to reaching Canada's climate targets, making sure family businesses can succeed in a changing climate, and keep food on people's plates. That is why the Government of Canada is making a significant new investment to support a sustainable future for Canadian farmers. That includes an investment of $470 million in the Agricultural Climate Solutions: On-Farm Climate Action Fund to help farmers adopt sustainable practices such as cover crops, rotational grazing and fertilizer management. The Government is also investing $330 million to triple funding for the Agricultural Clean Technology Program which supports the development and purchase among farmers of more energy-efficient equipment. The Government will also invest $100 million in transformative science for a sustainable sector in a changing climate and to support the sector's role in the transition to a net-zero economy for 2050, including fundamental and applied research, knowledge transfer, and developing metrics.

Maintaining Canada's approach to pricing pollution. Putting a price on pollution is widely recognized as the most efficient means to reduce greenhouse gas emissions. Without a strong price on pollution, achieving Canada's environmental goals would require additional actions. To enhance long-term certainty, the 2030 Emissions Reduction Plan commits the Government of Canada to exploring measures that help guarantee the price of pollution. This includes investment approaches, like carbon contracts for differences, which enshrine future price levels in contracts between the Government and low-carbon project investors, thereby de-risking private sector low-carbon investments. This also includes exploring legislative approaches to support a durable price on pollution.

Canada's Emissions Profile

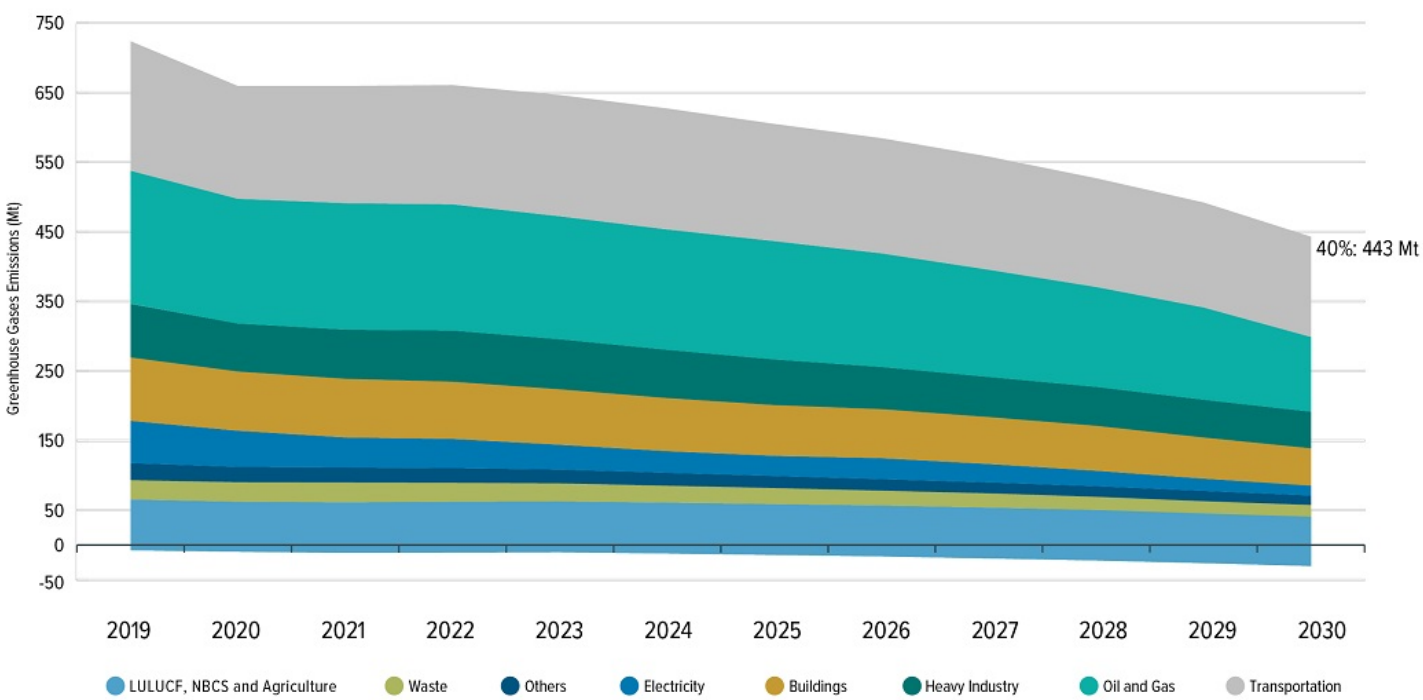
Canada's current emissions profile and historical trends are helpful for providing a clearer picture of where Canada needs to be by 2030 and 2050. As a party to the United Nations Framework Convention on Climate Change (UNFCCC), Canada is required to regularly develop, update, and publish its national inventory of human-sourced emissions. This is done through the Government of Canada's National Inventory Report (NIR), which is updated and submitted to the UNFCCC annually before April 15. Due to a data lag associated with GHG accounting and reporting, the most recent NIR (published in April 2021) documents Canada's annual GHG emissions estimates for the 1990–2019 period.

According to the NIR, total national greenhouse emissions were 730 million tonnes of carbon dioxide equivalent (Mt CO_2 eq) in 2019. Oil and gas and transportation continue to be Canada's largest sectoral emissions sources, with buildings, heavy industry, and agriculture following closely behind. Canada's 2019 emissions were approximately 9 Mt lower than in 2005. Since 2005, emissions in the oil and gas and transportation sectors have increased by 20 percent and 16 percent, respectively. Decreases in electricity (48 percent), heavy industry (12 percent) and waste and others (10 percent) have offset these increases.



▶ Long description

Pathway to 2030



▼ Long description

LULUCF = Land-Use, Land Use Change and Forestry. NBCS = Nature-Based Climate Solutions.

Note: Totals may not add up due to rounding.

Canada's greenhouse gas emissions pathway to 2030, measured in megatonnes of carbon dioxide equivalent (Mt CO_2 eq) (part 1)

Economic sector	2019	2020	2021	2022	2023	2024
LULUCF, NBCS and Agriculture (removal)	-8	-10	-11	-11	-10	-12
LULUCF, NBCS and Agriculture (emissions)	73	72	73	73	73	73
Waste	28	28	28	27	26	24
Others	24	22	21	21	20	19
Electricity	61	52	43	42	36	31

Economic sector	2019	2020	2021	2022	2023	2024
Buildings	91	85	84	82	80	76
Heavy industry	77	69	71	73	72	70
Oil and gas	191	179	182	181	177	173
Transportation	186	162	168	171	174	174
Total	**723**	**659**	**659**	**660**	**646**	**627**

Canada's greenhouse gas emissions pathway to 2030, measured in megatonnes of carbon dioxide equivalent (Mt CO_2 eq) (part 2)

Economic sector	2025	2026	2027	2028	2029	2030
LULUCF, NBCS and Agriculture (removal)	-14	-16	-19	-22	-26	-30
LULUCF, NBCS and Agriculture (emissions)	73	73	73	72	72	71
Waste	23	22	20	19	18	16
Others	17	16	16	15	14	13
Electricity	29	30	26	22	18	14
Buildings	73	71	6	65	62	53
Heavy industry	66	61	58	56	55	52
Oil and gas	170	163	154	144	128	110
Transportation	168	165	162	156	151	143
Total	**605**	**584**	**558**	**527**	**492**	**443**

What does cutting emissions mean for Canadians?

- **Good, sustainable jobs:** The Royal Bank of Canada (RBC) analysis suggests that the clean economy could create between 235,000 and 400,000 new jobs in Canada by 2030. By 2025, clean tech's contribution to Canada's GDP is expected to grow to $80 billion from $26 billion in 2016. Trends show Canada has been able to grow its economic output while decreasing emissions from some industries.

- **A strong, resilient economy for everyone** by positioning Canada to succeed in a world moving to clean, net-zero options. There is a major market evolution taking place, and Canada has the choice now to lead or be left behind.
- **Making life more affordable for the middle class:** Programs such as the Climate Action Incentive payments, which put money back in the pockets of families, while ensuring homes and buildings are energy efficient, will help homeowners save money on monthly bills.
- **Clean air:** Everyone deserves clean air to breathe. Each year, poor air quality is costing Canadians their lives, not to mention $120 billion due to illness and lost productivity. Reducing emissions improves air quality and quality of life.
- **Fighting inequality:** People marginalized through social, economic, cultural, gender, political or other factors are disproportionately impacted by climate change. Taking action to decarbonize the economy and fight climate change provides an opportunity to address these inequities.
- **More opportunities to enjoy nature:** Protecting nature such as through the Nature Smart Climate Solutions Fund not only helps fight climate change, but also means Canadians can enjoy the natural beauty of this country. From spending time with family to the benefits for mental health, this will boost Canadians' quality of life.
- **Climate resilience:** Nature-based solutions, such as the conservation of wetlands, pull carbon out of the air, while also mitigating flood risks, protecting Canadians and communities from climate risk.

How Canada's Emissions Modelling Works

The 2030 Emissions Reduction Plan uses economic modelling to show a pathway to achieving Canada's 2030 target, including the potential for each sector of the economy to reduce emissions by 2030. This modelling approach is widely used by other countries in charting their courses to net zero.

Broken down by sector, Canada's pathway to 2030 is based on today's understanding of the potential for each sector to reduce emissions by 2030. Given the economic interdependencies and interactions among sectors, the focus for further actions may shift in the future as Canada further decarbonizes, costs of abatement technologies change and other opportunities emerge.

The Government of Canada expects that the measures outlined in the 2030 Emissions Reduction Plan, together with complementary climate actions from the provinces and territories, municipalities, the financial community, Indigenous Peoples, innovators, and businesses—as well as with the acceleration of clean technology innovation and deployment—will lead to further emission reductions by 2030. Canada will continue to update its modelling projections, including in Canada's next Biennial Report in December 2022 and first 2030 Emissions Reduction Plan progress report expected in late 2023.

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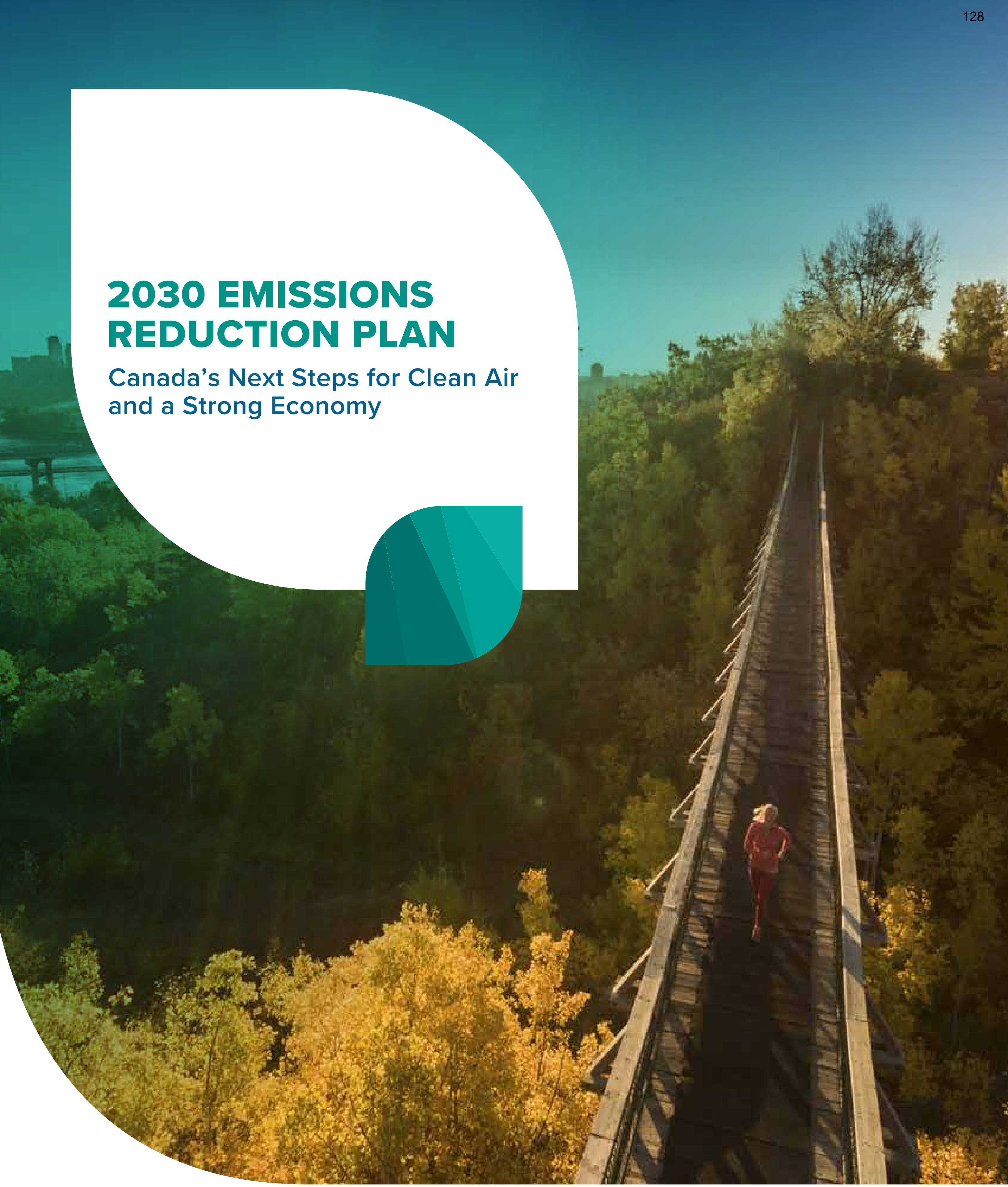
2030 EMISSIONS REDUCTION PLAN

Canada's Next Steps for Clean Air and a Strong Economy



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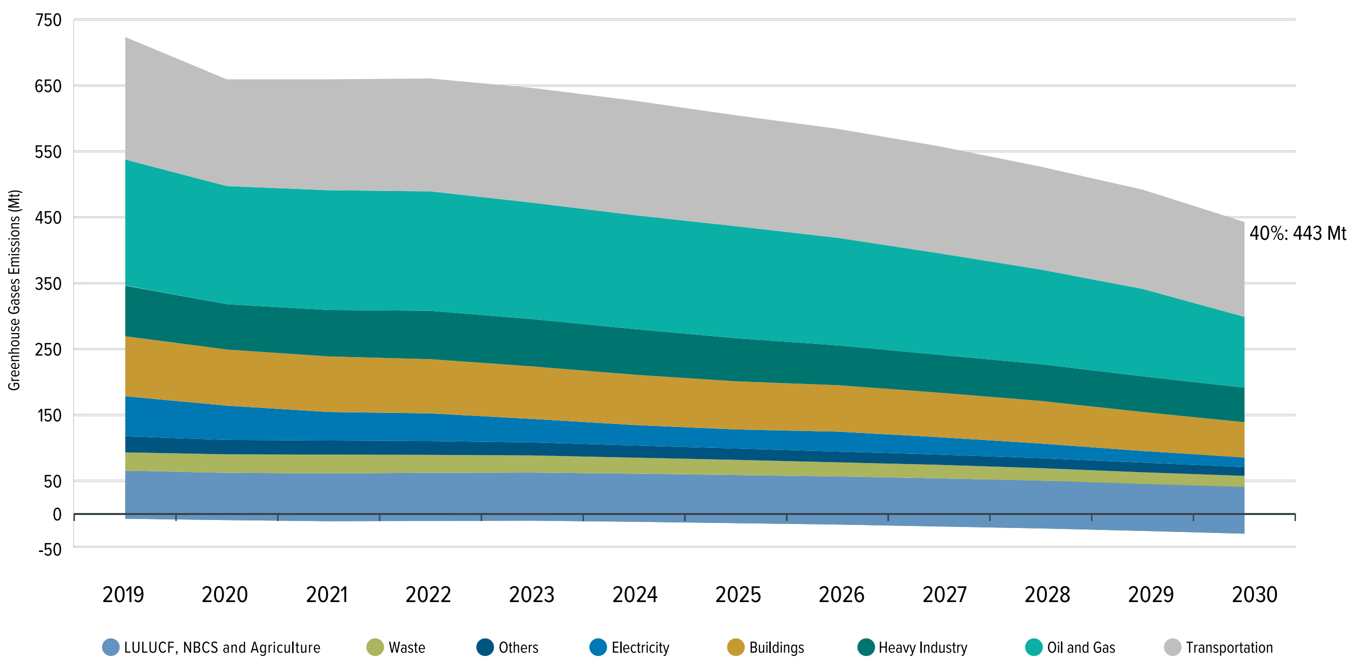
Canada

3.2 Canada's 2030 Trajectory

Broken down by sector, Canada's pathway to 2030 is based on today's understanding of the potential for each sector to reduce emissions by 2030. Given the economic interdependencies and interactions within and between sectors, the exact areas for emissions reduction potential may shift in the future as Canada further decarbonizes.

Canada's 2030 trajectory is indicative of where there is emissions reduction potential in key sectors to make additional progress. It is important to note that pathways are **not sectoral targets, they are projected sectoral contributions**: the emissions reductions ultimately contributed by each sector are likely to vary over time as Canada responds to real-world changes, such as other countries implementing their climate plans and changes in global demand for oil and natural gas.

Pathway to 2030



Canada's 2026 Interim GHG Objective

The Canadian Net-Zero Emissions Accountability Act specifies that Canada must establish a 2026 interim GHG objective. Based on Canada's current emissions reduction trajectory, Canada's 2026 interim objective will be 20% below 2005 levels by 2026. This interim objective is not an official target akin to the 2030 NDC, but progress towards achieving this target will be a cornerstone of future progress reports associated with this 2030 ERP in 2023, 2025, and 2027.

It is important to emphasize that the potential reductions presented here for each sector represent only one possible pathway to achieving the 2030 target, using an approach that considers the most economically efficient pathway to achieving Canada's 2030 target by sector, to provide an illustrative understanding of how emissions reductions could be distributed across sectors. While economic efficiency is important, there are other factors that will be key in determining Canada's ultimate trajectory to 2030. For example, technological feasibility, labour availability, and the enabling infrastructure needed to achieve modelled reductions are all considerations that will influence Canada's pathway to 2030 by sector. Despite this caveat, the model is still useful in providing an **indicative understanding** of how reductions could be distributed across sectors in an economically efficient way.

The following table outlines this notional pathway to 2030, based on the estimated potential for economy-wide and sectoral reductions. These indicative figures are based on the best available information at this time, including emissions data from the 2021 NIR, and are subject to future revision. As additional measures are developed, decarbonization dynamics between sectors evolve, and new data from the 2022 NIR becomes available, these numbers will change. The Government of Canada will continue to refine and update projections through future progress reports, as well as through UNFCCC reporting. The Government will submit Canada's Fifth Biennial Report to the UNFCCC by the December 31, 2022, deadline.

Sector	Where we were in 2005 (Mt)	Where we were in 2019[33] (Mt)	Where we could be in 2030 (Mt)	Per Cent Reduction from 2005 levels*	Key elements of Canada's Pathway
Buildings	84	91	53	-37%	A whole-of-government and whole-of-economy effort focusing on regulatory, policy, investment, and innovation levers is needed to drive decarbonization of the buildings sector. To this end, the Government will develop a national strategy for net-zero and resilient buildings, the Canada Green Building Strategy and support communities to upgrade and retrofit homes and buildings, including affordable housing though the Greener Homes Loan Program. (See Chapter 2.2)
Electricity	118	61	14	-88%	Significant effort has been made to decarbonize Canada's electricity grid, which is already 82% zero-emitting. Achieving a net-zero electricity grid by 2035 will be key to powering Canada's economy with clean energy. Key measures will continue to increase the supply of clean energy and the construction of interties while maintaining reliability and affordability. (See Chapter 2.3)

33 2021 Canada's National Inventory Report