COURT FILE NUMBER	KB-RG-0848 of 2023

COURT OF KING'S BENCH FOR SASKATCHEWAN

JUDICIAL CENTRE	REGINA
APPLICANTS	SABRINA DYKSTRA, JILL FORRESTER, RYAN HEISE, KAYLA HOPKINS, LYNN OLIPHANT, HAROLD PEXA, AMY SNIDER, and CLIMATE JUSTICE SASKATOON ORGANIZATION INC.
RESPONDENTS	SASKATCHEWAN POWER CORPORATION, CROWN INVESTMENTS CORPORATION OF SASKATCHEWAN, and THE GOVERNMENT OF SASKATCHEWAN

AFFIDAVIT

AFFIDAVIT OF EXPERT WITNESS DR. DAVID D. MAENZ

I, DR. DAVID D. MAENZ, of the City of SASKATOON, SASKATCHEWAN, MAKE OATH AND SAY (or AFFIRM):

1. I hereby provide this opinion to the Court in my capacity as a resident of Saskatchewan with broad expertise in climate change, climate change mitigation, and carbon pricing and policies designed to reduce greenhouse gas (GHG) emissions.

2. I provide this opinion evidence contained herein in an objective and non-partisan manner. My opinion evidence provided herein is related only to matters within my areas of expertise. I am aware of my duties as an expert witness to assist the Court as prescribed in *The Queen's Bench Rules* at rule 5-37 and I have made this submission in conformity with those duties.

3. I am a Canadian citizen.

4. I am the co-founder of MCN BioProducts and the inventor or co-inventor of 7 patents in the area of processing of oilseed crops to produce high valued products. I am the author of 23 scientific publications and 2 book chapters related to food science. Attached to this affidavit as **Exhibit "A"** is my Curriculum Vitae, which further describes my qualifications in greater detail.

5. In 2015, I retired from business interests and over the next two and a half years dedicated my efforts to researching and writing *The Price of Carbon*.[1] The book was published in 2017 as a fact-based narrative on the subject of anthropogenic (man-made) climate change, future outcomes under various scenarios of GHG emissions, technical pathways of climate change mitigation, international climate agreements, the effectiveness and cost-efficiencies of carbon pricing and regulatory policies designed to cut emissions, and the obligations of countries and subnational regions to contribute to the global effort to combat climate change.

6. I contributed to the submissions of an intervener group in the matter of the Greenhouse Gas Pollution Pricing reference hearings before the Court of Appeals of Alberta, the Court of Appeals of Saskatchewan, and the Supreme Court of Canada.

7. I have completed technical assessments of pathways to cut greenhouse gas emissions in multiple sectors including electricity supply. Specifically, I have recently completed a technical assessment of policy drivers, costs, and impacts on options for transitioning the electricity supply sector in Saskatchewan to Net-Zero emissions by 2035. Affixed to this affidavit as **Exhibit "B"** is a true copy of that paper entitled *Pathways to a Cost-Effective Transition of Saskatchewan's Electricity Supply to Net Zero or Net Negative Emissions by 2035* ["*Pathways to Net-Zero*"]. I have also made presentations to SaskPower on potential pathways of transition to net zero and net negative emissions electricity supply in Saskatchewan.

8. As discussed in my paper, *Pathways to Net-Zero*, SaskPower has announced a year 2030 target of achieving a 50% cut in greenhouse gas emissions from the provincial electricity supply sector relative to emissions on record for 2005. This level of ambition is consistent with shut down of the coal-fired generation and an expansion of the current fleet of natural gas plants to include the Great Plains Power Station, the proposed Lanigan facility, and an additional yet to be announced facility of similar size. SaskPower's plan for the past many years could be described plainly as a coal to gas transition (plus a modest increase in wind energy). SaskPower's current plan, as discussed in *Pathways to Net-Zero*, will likely rely on unabated gas-fired generation for over 70% of the electricity supply by year 2030 (Figure 4 of Exhibit "B").

9. The International Energy Agency (IEA) recently published a flagship report on pathways of transition of the global energy sector to Net Zero Emissions (NZE) by 2050.[2] Under the IEA NZE scenario, electricity supply sectors in advanced economies are projected to rapidly

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[1] David D. Maenz, *The Price of Carbon* (Victoria, BC: Tellwell Publishing, 2017).
[2] Stéphanie Bouckaert *et al, Net Zero by 2050. A roadmap for the global energy sector* (Paris: International Energy Agency, 2021), online: https://www.iea.org/reports/net-zero-by-2050 (4 Feb 2023).

transition to net zero emissions by 2035. This transition provides the foundation for fuel switching from fossil energy to clean electricity and thus deep cuts in emissions within the transportation, industry, and buildings sectors of advanced economies such as Canada.

10. The federal government of Canada has a stated goal of transitioning to a Net-Zero national electricity sector by 2035.[3]

11. The federal government has also proposed new Clean Electricity Regulations (CERs) to govern emissions from electricity supply sectors in Canada.[4] The proposed federal government CERs are designed to incentivize provincial and territorial governments and utilities to transition to Net Zero electricity supply sectors by 2035. The CERs are expected to subject all electrical generation plants to substantive carbon pricing.

12. Between 2019 – 2022 emissions from SaskPower were subjected to carbon pricing above the threshold established by the federal Output Based Pricing Systems regulations (OBPS).[5] The federal OBPS system applied to electrical generation in Saskatchewan because Saskatchewan's own OBPS regulations did not apply to electrical generation at the time. The pollution price rose from \$20/tonne of CO2 emissions in 2019 to \$50/tonne of CO2 emissions in 2022; but that pollution price applied only to emissions above established standards set for generation of electricity (with a different threshold depending on fuel type). For example, throughout the period of 2019 – 2022 the established output-based standard for existing gas-fired electricity generation was steady at 370 tonnes CO2e/GWh. SaskPower customers therefore paid pollution prices based on blended performance of the SaskPower generation fleet that was above the established thresholds for each generation fuel type.

13. The CERs contemplate revisions to the treatment of electricity generation under the OBPS as part of the process to set Canada on a path to cut more emissions by 2030 and to achieve a 100% net-zero emitting electricity system by 2035. The CERs would replace existing regulations as of January 1st, 2035. The CERs propose that the output-based standards for generation will be reduced substantially to near-zero. This means that SaskPower customers will be affected by both the rising price on pollution and the decrease in output-based performance standards for generation. In the period of 2019-2022 SaskPower customers only

[3] Government of Canada, *A Clean Electricity Standard in Support of a Net-Zero Electricity Sector: Discussion Paper* (Ottawa: 2022), online: https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/achieving-net-zero-emissions-electricity-generation-discussion-paper.html (4 Feb 2023).
[4] Government of Canada, *Clean Electricity Regulations* (Ottawa: 2022), online: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity-regulation.html (4 Feb 2023).
[5] *Output-Based Pricing System Regulations*, SOR/2019-266.

paid pollution pricing on approximately 20% of the total pollution associated with their electricity (the approximate amount that exceeded the performance standards), but by year 2035 it is anticipated that pollution pricing will apply to as much as 90% of the pollution associated with electrical generation. Emissions pricing is likely to double the levelized cost of electricity such that unabated fossil-fuel based electrical generation units will be uneconomic to operate as providers of bulk baseload levels of electricity.

14. On November 22, 2022, the federal government approved Saskatchewan's proposal for an updated Output-Based Performance Standards (OBPS-SK) program, which now includes electricity generation. As a result, the 2023-2030 carbon levy revenue SaskPower collects is now paid to the provincial government, effective January 1, 2023. The OBPS-SK system generally needs to incorporate an equivalent pollution pricing stringency to the federal system in order to meet the minimum stringency criteria prescribed by the federal government. Therefore, despite the provincial OBPS-SK now applying to electrical generation in Saskatchewan, it is likely Saskatchewan will still face the compound effects of rising pollution pricing and more stringent performance standards for electrical generation as prescribed by the federal government.

15. Saskatchewan's unabated coal-fired power plants are expected to be shut down before Jan 1st, 2030, when the provincial equivalency agreement expires and the federal regulations governing coal fired generation apply.[6] The current plan is to replace the coal-fired capacity primarily with new build or upgraded unabated gas power plants. The 289 MW North Battleford Power station was commissioned in 2013. In 2016 extensive upgrades of the 623 MW Queen Elizabeth Power Station were completed. The new build 353 MW Chinook Power Station came on-line in 2019. A 360 MW unabated combined cycle natural gas plant is under construction near Moose Jaw (Great Plains Power Plant) along with expansion of existing power plants (46 MW added to Ermine Power Station and 46 MW added to Yellowhead Power Station). SaskPower indicates another proposed 370 MW unabated gas power plant is under consideration for the Lanigan area.

16. Based on publicly available information, by 2030 about 70% of the electricity supplied to Saskatchewan will come from unabated natural gas power plants. The bulk of these assets were designed and costed to continue operation well past 2035. Continued operation of these gas plants would emit about 7.7 million tonnes of CO2 on an annual basis. Achieving the

[6] Government of Canada and Government of Saskatchewan, *An Agreement on the Equivalency of Federal and Saskatchewan Regulations for the Control of Greenhouse Cas Emissions from Electricity Producers in Saskatchewan, 2020*, (Ottawa: 2019) online: https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/agreements/equivalency/canada-saskatchewan-greenhouse-gas-electricity-producers.html (4 Feb 2023).

national ambition of transitioning to a Net Zero electricity system by 2035 would be jeopardized by this level of emissions from Saskatchewan. Many of the unabated natural gas power plants face premature obsolescence given the trajectory of pollution pricing in Canada (and as influenced by international markets and proposed Border Carbon Adjustment Tariffs).

17. Saskatchewan is rich in potential for electricity generation from wind and solar. The Levelized Cost of Electricity (LCOE) refers to the revenues required per unit of electricity sold over a specified period (usually the anticipated lifespan of the generation equipment) to cover the costs of building and operating the facility. In recent years, with advances in the technology and broader application, the LCOE for unsubsidized onshore wind farms has dropped dramatically. Wind is now the lowest cost option for generating electricity. In 2021, the LCOE for onshore wind was in the range of $26-$50 USD/MWh.[7] In comparison, the LCOE for an unabated natural gas combine cycle plant ranges from $45-$74 USD/MWh.[8] Significant expansion of renewables in Saskatchewan will require access to large-scale hydro, or another energy storage option to provide a dispatchable zero emissions power source. These zero and negative emissions options could replace unabated natural gas power plants to generate electricity in Saskatchewan.

18. In addition, the province is well positioned to take a global leadership role in the implementation of negative emissions bioenergy with carbon capture and storage.

19. Alternatively, Saskatchewan could apply carbon capture and storage to all new gas-fired electricity generation to control emissions and mitigate the risk of premature obsolescence.

20. Put simply, SaskPower unabated natural gas generation is not the only viable alternative to replacing existing coal-fired generation, but the transition from coal to unabated gas generation is not compatible with a Net-Zero electricity supply by 2035 and this path risks Saskatchewan consumers facing unreasonable electrical rates caused by rising pollution pricing and more stringent performance standards for electricity generation.

21. SaskPower's current plan to execute a coal to gas transition risks undermining the Crown Investment Corporation's ability to control electricity rates for Saskatchewan consumers. Rising pollution prices (projected to reach $170/tonne by 2030) coupled with more stringent performance standards for electrical generation will mean that pollution prices applied to electricity supplied by unabated gas generation will be expensive and, therefore, greatly

[7] Larzard, "Levelized Cost Of Energy, Levelized Cost Of Storage, and Levelized Cost Of Hydrogen," (28 October 2021), online: https://www.lazard.com/perspective/levelized-cost-of-energy-levelized-cost-of-storage-and-levelized-cost-of-hydrogen/ (4 February 2023).

[8] *Ibid.*

diminish the ability of the Crown Investment Corporation to control electricity rates. The proposed CERs, though not yet finalized, are likely to further increase pollution pricing on electricity generation when the CERs come into effect.

22. The Federal Government of Canada has proposed establishing a Pan-Canadian Grid Council to operate in partnership with the provinces, territories, the private sector, Indigenous peoples, labour unions, and civil society with the mandate to work toward establishing a reliable, cost-effective, and equitable net-zero or net-negative emissions electricity sector in Canada by 2035. Expanding interprovincial transmission capacity, grid modernization, and intertie agreements with other provinces would provide Saskatchewan with access to large scale zero emissions hydro power and facilitate a full realization of the potential for renewables. Under conditions of excess generation from renewables, power would flow to hydro-rich regions and generation would be turned down in Manitoba and British Columbia. Hydro would accumulate in reservoirs for latter use when renewables are not producing to meet demand. Equitable solutions to issues of stranded assets would be part of the overall transition to a clean electricity system across Canada.

23. Modelling work focused on least cost options for electricity generation in Saskatchewan, when interprovincial transmission is assumed, indicate an optimal installed wind generation capacity for Saskatchewan of 27,600 MW.[9] Affixed to this Affidavit as **Exhibit "C"** is a copy of this study entitled "The Cost of Decarbonizing the Canadian Electricity System" by authors Dolter and Rivers. The suggested 27,600 MW of wind generation capacity is 4-fold greater than the current total installed capacity to generate electricity from all energy sources in the province. Nationally, under a year 2035 net zero electricity sector scenario, wind generation would be concentrated in Southern Saskatchewan with greatly expanded interprovincial electricity transmission lines to both import and export electricity (as shown in Figure 9 of Exhibit C).

24. Without federal assistance, the burden of cost of upgrading Canada's electricity generation and supply infrastructure will vary considerably between provinces. Provinces that are currently dependent upon fossil fuel for generation of electricity (Alberta, Saskatchewan and Nova Scotia) could be disproportionally burdened by costs relative to hydro-rich provinces.[10] Further, in the absence of alternate funding mechanisms, lower income households that pay a higher proportion of their monthly income toward utility bills will be disproportionally impacted by higher

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[9] Dolter, B. and Rivers, N., "The Cost of Decarbonizing the Canadian Electricity System" (2018). Energy Policy 113: 135-148, online: https://www.sciencedirect.com/science/article/abs/pii/S0301421517307140?via%3Dihub (4 February 2023).

[10] Brett Dolter & Jennifer Winter, *Electricity Affordability and Equity in Canada's Energy Transition: Options for rate design and electricity system funding* (Canadian Climate Institute: 2022) at 36, online: https://climateinstitute.ca/wp-content/uploads/2022/09/Electricity-and-equity-canadas-energy-transition.pdf (4 Feb 2023).

electricity rates. As such, in the absence of federal assistance, the Government of Saskatchewan is justified in expressing concerns that the disproportional costs of a clean electricity transformation will be passed on to consumers and industry in the province. This is described in the article by Dolter and Winter entitled: "Electricity Affordability and Equity in Canada's Energy Transition" which is affixed to this Affidavit as **Exhibit "D."**

25. However, recent economic modelling of funding options has led to the concept of "Electric Federalism",[11] whereby, the federal government would commit taxpayer funds to provincial governments for the express purpose of building transmission and clean electricity generation capacity. Funding would be contingent upon provincial governments agreeing to develop net zero plans that align with the over-arching ambition to complete the transition to a Net Zero electricity system across Canada by 2035.

26. If, as an example, the Government of Canada where to finance 50% of new investments in generation, transmission, distribution, and storage cost by way of federal taxes, provinces with greater costs of transition would receive proportionally greater federal funding. Under this funding scenario, relative to 2020, the economic model of the transition to clean electricity in Saskatchewan is consistent with no change in the electricity consumption unit cost for households going forward to 2050.[12]

27. Clearly, it is in the best interests of Saskatchewan, to partner with the federal government and other provincial governments and stakeholders, under a program of "Electric Federalism," to develop an equitable funding model based on significant federal assistance in the covering the costs of transition to a net zero emissions clean electricity sector by 2035.

28. The provincial government of Saskatchewan would be wise to recognize the need to decarbonize the provincial electrical supply to mitigate the causes of climate change, to protect Saskatchewan citizens from rising pollution prices, to avoid the risk of obsolescent unabated gas-fired power plants, and to supply Saskatchewan industry and manufacturing with cost-effective clean power to reduce scope 2 emissions associated with electrical demands.

29. There are numerous forms of clean electricity generation that SaskPower should pursue rather than persistent adherence to the present coal to unabated gas fired generation, otherwise Saskatchewan residents are likely to face expensive electricity as pollution prices rise and Saskatchewan will struggle to decarbonize its economy.

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[11] *Ibid* at 29.
[12] *Ibid* at 31.

SWORN (OR AFFIRMED) BEFORE ME via electronic means,
at, Saskatoon, Saskatchewan,
this 20th day of March,
2023.

Commissioner for Oaths
for Saskatchewan
Being a Solicitor

(signature)

MAENZ, DAVID DANIEL
Curriculum Vitae

ACADEMIC CREDENTIALS:

B.Sc., University of Guelph, 1979, Department of Nutritional Sciences, Nutritional Biochemistry
Ph.D., University of Saskatchewan, 1984, Department of Biochemistry, Membrane Transport

APPOINTMENTS

President and Chief Scientific Officer. Maenz Consulting. Saskatoon, SK, May 2012 – present.

Chief Scientific Officer. MCN BioProducts Inc. Saskatoon, SK, Jan. 2001- 2012.

Adjunct Professor. University of Saskatchewan, Dept of Animal and Poultry Science, Saskatoon, SK, Nov. 2006 – present.

Manager, Research and Development. Prairie Feed Resource Centre Inc. Department of Animal and Poultry Science, University of Saskatchewan, Saskatoon, SK, Sept. 1998 – Jan. 2001.

Professional Research Associate. University of Saskatchewan, Saskatoon, SK, Sept. 1990-Sept. 1998.

Post Doctoral Fellow, University of Montreal, Montreal, Quebec, 1987-1990.

Post Doctoral Fellow, University of Alberta, Edmonton, Alberta, 1984-1987.

CLIMATE CHANGE MITIGATION PRESENTATIONS AND PUBLICATIONS:

Books:

1. Maenz, D.D. 2017. The Price of Carbon. One Ton Press. Saskatoon, SK. www.thepriceofcarbon.com

On-Line Publications:

1. Maenz, D.D. 2023. Pathways to a Cost-Effective Transition of Saskatchewan's Electricity Supply to Net Zero or Net Negative Emissions by 2035. Saskatchewan Coalition for Sustainable Development. https://www.sustainablesask.ca/pathways-to-net-zero.html

2. Maenz, D.D. 2023. Achieving Net Zero 2050 in Canada: The Critical Roles of Forest Adaptation, Biomass, and Carbon Capture and Storage. Saskatchewan Coalition for Sustainable Development. ccs_knowledge_center_submission_jds_r2.pdf (sustainablesask.ca)

Presentations:

1. Maenz, D.D. 2022. Citizens' Climate Lobby Canada: November Education Call. A Discussion with Dr. David Maenz About the Parliamentary Budget Office PBO Report: A Distributional Analysis of the Federal Carbon Pricing Under a Healthy Environment and a Healthy Economy. CCL Canada November Education Call with Dr. David Maenz w.r.t. "that" PBO report - Citizens' Climate Lobby Canada (citizensclimatelobby.org)

2. Maenz, D.D. 2019. Saskatchewan Energy Management Task Force. The Potential for Early Adoption of Bio-Energy with Carbon Capture and Storage in Saskatchewan. EMTF Stationary (emtfsask.ca)

3. Maenz, D.D. 2018. Citizens' Climate Lobby Canada: CCL Canada Education: Shell's Sky Scenario. CCL CANADA EDUCATION: Shell's Sky Scenario, Dr. David Maenz Tuesday, May 29, 2018, - Citizens' Climate Lobby Canada (citizensclimatelobby.org)

4. Maenz, D.D. 2018. Citizens' Climate Lobby Canada: 2018 National Conference and Lobby Days. Citizens' Climate Lobby Canada's 2018 National Conference and Lobby Days - Citizens' Climate Lobby Canada (citizensclimatelobby.org)

OTHER PRESENTATIONS AND PUBLICATIONS:

Book Chapters and Review Articles

1. Maenz, D.D., 2000. In M. Bedford and G. Partridge (eds.), Enzymes in Farm Animal Nutrition. CAB International: Wallingford.
2. Berteloot, A. and D.D. Maenz, 1990. In R.K.H. Kinne (ed.), Comparative Physiology, 7, 130-185. Basel: Karger.

Peer Reviewed Publications in Scientific Literature

1. D.L. Thiessen, D.D. Maenz, R.W. Newkirk, H.L. Classen and M.D. Drew. 2004. Aquacult. Nutr. 10, 379-388.
2. Yu, P., J.J. McKinnon, D.D. Maenz, V.J. Racz, and D.A. Christensen. 2004. J. Chem. Tech. Biotech. 79:729-733.
3. Yu, P., J.J. McKinnon, D.D. Maenz, A.A. Olkowski, V.J. Racz, and D.A. Christensen. 2003. J. Agri. Food Chem. 51, 218-223.
4. Yu, P., J.J. McKinnon, D.D. Maenz, V.J. Racz, and D.A. Christensen. 2002. Can. J. Ani. Sci. 82, 251-257.
5. Thompson, R.K., J.J. McKinnon, D.D. Maenz, V.J. Racz and D.A. Christensen. 2002. Can. J. Ani. Sci. 82, 103-109
6. Yu, P., D.D. Maenz, J.J. McKinnon, V.J. Racz, and D.A. Christensen. 2002. J. Agri. Food Chem. 50, 1625-1630.
7. Thompson, R.K., A.F. Mustafa, J.J. McKinnon, D.D. Maenz, B. Rossnagel, 2000. Can. J. Ani. Sci. 80, 377-379.
8. D.D. Maenz, C.M. Engele-Schaan, R.W. Newkirk and H.L. Classen, 1999. Ani. Feed Sci. Tech. 81, 177-192.
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10. G.G. Irish, D.D. Maenz, and H.L. Classen, 1999. Ani. Feed Sci. Tech. 76, 321-333.
11. H. Kermanshahi, D.D. Maenz, and H.L. Classen, 1998. Poult. Sci. 77, 1665-1670.

12. H. Kermanshahi, D.D. Maenz and H.L. Classen, 1998. Poult. Sci. 77, 1671-1677.
13. D.D. Maenz, and H.L. Classen, 1998. Poult. Sci. 77, 557-563.
14. D.D. Maenz and J.F. Patience, 1997. Biochem. Cell Biol. 75, 229-236.
15. D.D. Maenz and C.M. Engele-Schaan, 1996. J. Nutr. 126, 1438-1444.
16. D.D. Maenz and C.M. Engele-Schaan, 1996. J. Nutr. 126, 529-536.
17. D.D. Maenz, J.F. Patience and M. Wolynetz, 1994. J. Ani. Sci. 72, 300-308.
18. D.D. Maenz, Chenu, C. and A. Berteloot, 1993. J. Biol. Chem. 268, 15361-15367.
19. D.D. Maenz and J.F Patience, 1993. Can. J. Ani. Sci. 73, 669-672.
20. D.D. Maenz and J.F Patience, 1992. J. Biol. Chem. 267, 22079-22086.
21. D.D. Maenz, C. Chenu and A. Berteloot, 1992. J. Biol. Chem. 267, 1510-1516.
22. D.D. Maenz, C. Chenu, F. Bellemare and A. Berteloot, 1991. Biochem. Biophys. Acta, 1069, 250-258.
23. C.I. Cheeseman and D.D. Maenz, 1989. Am. J. Physiol. 265, G878-G883.
24. K. Lawless, D.D. Maenz and C.I. Cheeseman, 1987. Am. J. Physiol. 253, G637-G642.
25. D.D. Maenz and C.I. Cheeseman, 1987. J. Memb. Biol. 97, 259-266.
26. D.D. Maenz, S.E. Gabriel and G.W. Forsyth, 1987. J. of Memb. Biol. 96, 243-249.
27. D.D. Maenz and G.W. Forsyth, 1987. Digestion 36, 220-229.
28. D. Davies, D.D. Maenz and C.I. Cheeseman, 1986. Biochem. Biophys. Acta, 896, 247-255.
29. D.D. Maenz and C.I. Cheeseman, 1986. Bioch. Biophys. Acta, 860, 277-285.
30. D.D. Maenz and G.W. Forsyth, 1986. Can. J. of Physiol. and Pharm. 64, 568-574.
31. G.W. Forsyth, P.H. Wong and D.D. Maenz, 1985. Can. J. Comp. Med. 49, 179-185.
32. D.D. Maenz and G.W. Forsyth, 1984. Digestion 30, 183-150.
33. D.D. Maenz and G.W. Forsyth, 1982. J. Memb. Biol. 70, 125-133.

INVITED CONFERENCE PRESENTATIONS: 24 National and International Conference Presentations

AWARDS:

1. 2004 Innovation Place/University of Saskatchewan Industry Liason Office - Award of Innovation.

PATENTS GRANTED OR PENDING:

1. Process for Converting Phytate into Inorganic Phosphate.
- Inventors: D.D. Maenz, H.L. Classen and R.W. Newkirk.
- U.S. Patent 6,284, 502. Issued: Sept. 4, 2001
- Issued: 32 Countries.

2. Fractionation and Processing of Oilseed Meal.
- Inventors: D.D. Maenz, R.W. Newkirk, H.L. Classen and R.T. Tyler.
- U.S. Patent 6,800,308. Issued: Oct. 5, 2004
- Issued: 31 Countries.

3. Dephytinization of Plant Based Products in Mixtures with Raw or Ensiled Animal or Fish Based Products.
- Inventors: R.W. Newkirk, D.D. Maenz, H.L. Classen.
- Canadian Patent 2,406,112. Issued June 6, 2010
- Issued: 7 Countries.

4. Oilseed Processing.

- Inventors: D.D. Maenz, H.L. Classen and R.W. Newkirk.
- U.S. Patent 7,090,887. Issued Aug. 15, 2006
- Issued: 20 Countries.

5. Filtration of Vegetable Slurries.

- D.D. Maenz, H.L. Classen and R.W. Newkirk.
- U.S. Patent 7,989,011. Issued Aug. 2, 2011
- Issued: 12 Countries.

6. Isolation of Inositol.

- D.D. Maenz, H.L. Classen and R.W. Newkirk.
- U.S. Patent 8,012,512. Issued Sept. 6, 2011
- Issued: 8 Countries.

7. Process for Aqueous Oil Extraction from Oilseed Starting Material.

- D.D. Maenz
- U.S. Patent Application 20100040748
- Issued: 4 Countries.

Pathways to a Cost-Effective Transition of Saskatchewan's Electricity Supply to Net Zero or Net Negative Emissions by 2035

David D. Maenz, Ph.D.

Executive Summary

Clean electricity across Canada is essential to complete an economy-wide transition to Net Zero emissions by mid-century. While 80% of Canada's electricity is already sourced from zero emissions sources, some provinces rely heavily on fossil fuel-based generation and do not have access to the hydropower baseload necessary to support renewables. Continued emissions from electricity generation in Saskatchewan, Alberta, and Nova Scotia past 2035 will compromise the national ambition to decarbonize and may position these provinces at a competitive disadvantage as surrounding economies rapidly decarbonize and pollution prices rise.

Clean Electricity Regulations are expected to be proclaimed by the federal government in 2023. These regulations are being designed to drive the transition of Canada's electricity sector to net zero or net negative emissions by 2035. More interprovincial transmission capacity and grid interconnectivity between provinces is needed to maximize the development of renewable wind and solar resources in the prairies. In the absence of a cooperative intertie agreements between the provinces, the wind and solar potential of Alberta and Saskatchewan will remain under utilized. Collaboration between provincial and federal governments is necessary to build a national clean power grid. Establishing a Pan-Canadian Grid Council could facilitate collaboration to realize the goal of a Net Zero electrical grid, or perhaps even a Net Negative Emissions Grid by 2035. This paper explains the most practical pathways to achieve these ambitious, but realistic, goals.

Background

The overarching goal of the Paris Agreement is to limit global surface warming to well below 2°C and ideally no more than 1.5°C above average surface temperatures of the pre-industrial era (1). Achieving this level of ambition requires that advanced economies transition to net zero emissions by 2050. Canada is one country, on a growing list of 133 countries accounting for 83% of global emissions, that has established a Net Zero target date (2). The Canadian Net-Zero Emissions Accountability Act became law on June 29th, 2021, and established Canada's commitment to achieving net zero emissions by 2050 (3).

The International Energy Agency (IEA) is the world authority in providing analysis and policy recommendations to governments and industry regarding the global energy sector. In 2021, the IEA published a flagship report on pathways of transition to net zero emissions by 2050 (4). This report was updated in the 2022 IEA World Energy Outlook (5). Under the IEA Net Zero Emissions (NZE) scenario, electricity supply sectors in advanced economies rapidly transition to net zero emissions by 2035. Total electricity supply increases by 3.3% on an annual basis leading to a 50% increase by 2035. The transition to NZE electricity sectors by 2035, along with the increase in generation capacity, provides the foundation for electrification of practices (clean electricity replacing fossil fuel use) and thus deep cuts in emissions within the transportation, industry, and buildings sectors of advanced economies.

The federal government of Canada has a stated goal of transitioning to a Net Zero national electricity sector by 2035 (6). A timely transition to clean electricity across Canada is an essential pillar in completing an economy-wide transition to Net Zero emissions by mid-century.

Canada can Build a Net Zero Emissions or even *Net Negative Emissions* Electricity Sector by 2035

Canada has the fourth largest installed hydropower capacity in the world, and in 2019, 60% of Canada's electricity supply came from zero emissions hydropower (7). In total, 80% of the country's electricity was generated by zero emissions sources in 2019 (hydro, nuclear, and renewables). This existing capacity for clean power generation in combination with untapped regional potential for renewables, places Canada in an advantageous position to complete a timely transition to clean electricity.

In addition to an abundance of hydro and renewables, Canada's forestry, agriculture, and municipal sectors produce vast quantities of residue biomass that can be collected and used on a sustainable annual basis. Canada's forestry sector produces about 46 million tonnes per year of dry residues (8). Canada also produces another 48 million tonnes of agriculture residues and 25 million tonnes of dry municipal solids waste annually (8). The energy content of this waste biomass is 2 to 3-fold greater than the energy content of total quantity of coal burned in Canada in 2013 (8). Waste biomass can be used for heat production and/or electricity generation or it can be converted to secondary energy carriers such as hydrogen. Bioenergy with Carbon Capture and Storage (BECCS) generally refers to the use of biomass to produce heat and/or electricity with capture of CO_2. The carbon in the biomass was removed from the atmosphere during the growth stage of the plants and during combustion reacts with oxygen to form CO_2. Captured carbon dioxide is then permanently stored in geological formations and isolated from the biosphere. As such, BECCS is a negative emissions technology because the net result is that carbon is removed from the biosphere and sequestered within the lithosphere in deep geological storage. On a life cycle assessment basis that tracks emissions along the full biomass supply chain, a BECCS power plant can function to remove up to 1,100 kg of CO_2 from the atmosphere per MWh of electricity generated (9).

The Western Canada Sedimentary Basin (WCSB) is a massive, in-land, stable geological formation found under much of Alberta and Saskatchewan (10). The WCSB is ranked as a world-class resource for the safe, cost-effective, and permanent storage of CO_2 captured from industrial processes. Implementation of BECCS at scale in Alberta and Saskatchewan, in combination with clean hydro, nuclear, and renewables can transition Canada's electricity sector to net negative emissions by 2035.

With due consideration to Canada's natural resource potential to produce clean electricity, the challenges to completing this transition within 12 years are substantial. As it stands, electricity supply in Canada consists of various regional grids with limited or no connectivity. Regulations governing the generation of electricity falls under provincial jurisdiction. Canada's current structure of largely isolated electricity grids and regulatory frameworks is not conducive to an optimized use of renewable resources as required to transition to NZE or Net Negative Emissions (NNE) within 12 years. Existing grids currently based on fossil fuel power plants and without access to substantial baseload hydropower, are likely to be delayed in completing the transition. Continued emissions from electricity generation in Saskatchewan, Alberta, and Nova Scotia past 2035 will compromise the national ambition to decarbonize and may position these provinces at a competitive disadvantage as surrounding economies rapidly decarbonize, and pollution prices rise.

Pathway to a National NZE or NNE Electricity Sector by 2035

Pillar 1. Clean Electricity Regulations (CERs)

In 2023, the federal government is expected to release the full details of the proposed Clean Electricity Regulations. The CERs are being designed to drive the transition of Canada's electricity sector to net zero or net negative emissions by 2035. While the full details of the regulations are yet to be determined, the Government of Canada has published some high-level information as to the key components of the CERs (11). These can be summarized as follows:

1. A performance standard based on a maximum intensity of emissions would apply to all regulated electricity generating units. The standard will be set to a near zero value that would allow for operation of "well-performing, low-emitting generation such as geothermal or combined cycle natural gas with carbon capture and storage."
2. The performance standard comes into effect as of 2035. Prior to 2035, units will be subject to existing electricity sector policies.
3. **New units**. Continued operation of natural gas units commissioned after 2025 would require installation of abatement technology to bring the intensity of emissions below the standard. As such, the financial implications of the CERs should function to deter any new build unabated gas plants.
4. **Older units**. For natural gas units commissioned prior to 2025, the CERs standard would come into effect at the prescribed end-of-life or on Jan 1, 2035. The definition of prescribed end-of-life is yet to be determined but could be based on a fixed number of years from commissioning.
5. Unabated natural gas plants would be allowed to operate in emergency circumstances.
6. As of 2035, all regulated units (regardless of commissioning date) will be required to compensate financially for continued emissions (i.e. pay for continued pollution). Financial compensation mechanisms are to be determined but would likely include the payment for emissions based on the federal carbon price, or production or purchase of certified offsets including verified negative emissions.
7. A fleet averaging approach will be implemented (for example, the generation fleet of a province in the case of a Crown utility, or the entire fleet of a private business). This will incentivize building renewables and negative emissions facilities within a given fleet. Negative emissions could serve to offset continued emissions from unabated gas plants provided that the pooled emissions of the fleet meet the performance standard.
8. The CERs would not apply to "behind the fence" generators that do not sell electricity. However, other regulatory and pricing mechanisms may apply to emissions from these facilities. The treatment of co-generation facilities that consume their own electricity may be revised later.

In essence the upcoming CERs will be designed as a set of regulations to minimize continued operation of unabated fossil fuel generators (without provision of carbon offsets) past the year 2035. While there may be provisions for continued operation of unabated gas plants that were commissioned prior to 2025, emissions from these plants will be subject to significant carbon pricing. In the absence of offsets, continued operation of these plants beyond Jan 1st, 2035, as generators of substantial MWhs of electricity will be cost-prohibitive.

Pillar 2. Interprovincial Transmissions Lines, Interties and Grid Interconnectivity

Alberta and Saskatchewan do not have access to large capacity hydropower and currently are dependent on fossil fuels for baseload power production. Without further action or obvious cost-effective alternatives, these provinces will be disproportionally burdened by the CERs and will be delayed in completing the transition to clean electricity generation. As such, building east-west interprovincial transmissions lines, interties and grid modernization will be required to facilitate the transition to a national net zero or net negative electricity sector by 2035.

Recently, the David Suzuki Foundation published a report summarizing two potential pathways of transition to zero emissions electricity supply across Canada by 2035 (12). The Sustainable Energy Systems Integration and Transitions (SESIT) group at the University of Victoria led the modelling work in the report. The Zero emissions scenario was based on current projections by utilities for growth in baseload power while the Zero Plus scenario was based on accelerating the rate of electrification of buildings, transportation, and industry. The Suzuki Foundation defined a set of constraints that were placed on the modelling exercise. Renewable energy was the focus of this modelling. As such, all fossil fuel generation (including fossil fuel power plants with carbon capture and storage), all nuclear (including small modular reactors), new large-scale hydro dams, new large-scale biomass (including biomass with carbon capture and storage) and direct air capture (and/or other negative emissions technologies) were excluded from the scenarios.

Figure 1 shows the model output for an expansion of transmission capacity across Canada by mid-century under the Zero Plus scenario (80% increase in electricity demand by 2050) with the noted restrictions on technology use. In total, transmission capacity totalling 29 GW (6,000 km of lines) would be built between

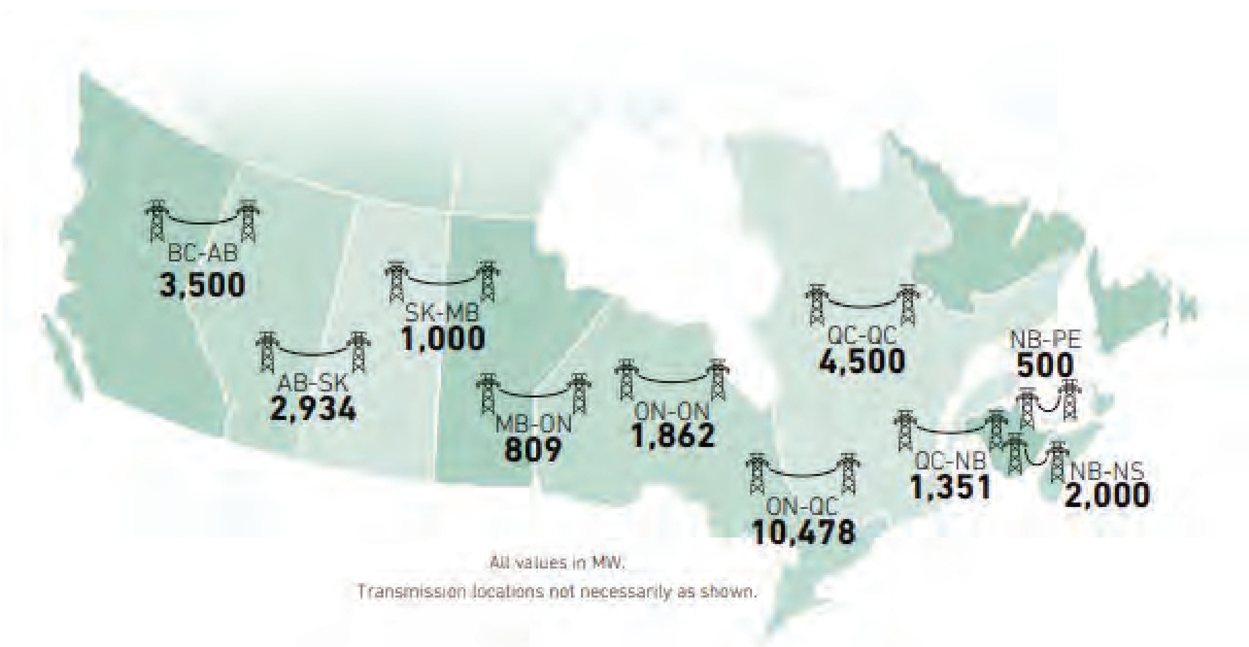

Figure 1. Expansion of Transmission Capacity Across Canada by 2050. Zero Plus pathway (high electrification) from "Shifting Power: Zero-Emissions Electricity Across Canada by 2035". Reproduced from "Shifting Power: Zero-Emissions Electricity Across Canada by 2035". The David Suzuki Foundation (12).

adjacent provinces and regions within provinces. About 1,000 MW of transmission capacity would be built between Manitoba and Saskatchewan plus another 3,000 MW between Alberta and Saskatchewan. A massive increase in renewables would be installed in the wind and solar rich provinces of Alberta and Saskatchewan. Under conditions of excess generation from renewables, power would flow to hydro-rich regions and generation would be turned down in Manitoba and British Columbia. Hydro would accumulate in reservoirs for later use when renewables are not actively producing electricity.

The magnitude of interprovincial transmission will vary with the energy mix for power generation. If other zero or negative emissions technologies are deemed acceptable, a least-cost analysis may lead to a mix of renewables in Alberta and Saskatchewan with abated fossil fuel plants (natural gas combined cycle with carbon capture and storage), small modular nuclear, and/or negative emissions technologies such as BECCS or direct air capture. Additional energy storage such as localized battery storage, pumped hydro and/or electrolysers for green hydrogen production could play an important role in the electricity system of the future. Ultimately, storage capacity and other energy sources would reduce the scale of, but not the requirement for, the cooperative flow of power between hydro rich and renewables rich regions of the country.

As of this writing there are few details in the public domain regarding the costs and timelines of building the transmission capacity and grid modernization required to support interprovincial and interregional flows of electricity.

The modelling work completed by the SESIT team at the University of Victoria provides some clarity as to the costs of building and maintaining Canada's electricity system going forward to mid-century. Total costs to build and operate the system, over the next 28 years, under a "business as usual" or status quo scenario were estimated at $430 billion (12). In comparison, the Zero emissions scenario (zero emissions electricity by 2035 with current projections for growth in demand) would cost $464 billion (12). The Zero Plus scenario is modelled at a cost of $560 billion; see Figure 1 (12). These costs include new interprovincial transmission infrastructure.

In a 2018 publication, Dolter and Rivers (13) estimated the costs of decarbonizing Canada's electricity sector by the year 2025 under various least-cost scenarios. The model assumed carbon pricing as the driver of decarbonization. The modelling did not consider negative emission electricity generation technologies. The modeling found that the least-cost energy sources to generate electricity varied with carbon price. As carbon pricing escalates up to $200/tonne, wind progressively displaces coal and natural gas from the national electricity generation portfolio. When interprovincial transmission was constrained in the modelling, at a carbon price of $200/tonne, national emissions were cut by 82% at a cost of $8 billion annually. When the modelling allowed expansion of interprovincial transmissions lines, electricity sector emissions were further reduced to 86.7% while reducing projected costs to $7.7 billion annually. When the model was further constrained to net zero emissions, annual costs increased by $16 billion annually in the absence of transmission and $11.8 billion annually with transmission. This study by Dolter and Rivers clearly demonstrates the cost benefit of building long-distance interprovincial transmission capacity.

The Canada Infrastructure Bank (CIB) was established to invest in the infrastructure required for Canada to meet emission reduction targets (14). Investment in clean power including electricity transmissions and storage and renewable energy sources is a priority for the CIB and $5 billion has been allocated toward investments in this area. Considerable additional financing will be required to build the transmission capacity and interties required for Canada to complete the transition to a clean electricity sector.

Pillar 3. A Collaborative Approach to Build a National Clean Power Grid

The current structure of sub-national electricity grids, governed and operating mostly in isolation, is incompatible with an equitable and cost-effective transition to net zero or net negative electricity sector across Canada by 2035. Hydro-rich regions of the country currently generate near zero emissions electricity, and little will be required of these regions to complete the transition. In contrast, Alberta and Saskatchewan do not have ready access to hydro at scale. Without obvious, zero emissions, dispatchable energy options to balance renewables, these provinces will be burdened by the practical limitations and high costs of transition. In the absence of a cooperative agreement on regulating interties between the provinces, the wind and solar potential of Alberta and Saskatchewan will remain under utilized.

The Government of Canada has proposed the concept of establishing a Pan-Canadian Grid Council (15). The council would operate in partnership with the provinces, territories, the private sector, Indigenous peoples, labour unions, and civil society and work toward establishing a reliable, cost-effective, and equitable NZE or NNE electricity sector in Canada by 2035. Given Canada's renewables resource potential, improved grid integration throughout the country could facilitate export of zero or negative emissions electricity to neighbouring markets in the USA.

Figure 2 summarizes milestones and timelines to complete the transition to a NZE grid by 2035 (16). The full details of the federal Clean Electricity Regulations will be announced in 2023. Without delay, provincial and federal governments and other stakeholders must commit to building inter-provincial transmission capacity and intertie agreements should be signed within 2 years. Agreements must be mutually beneficial and cost-effective using a least-cost approach to implementation of approved technologies. Equitable solutions to issues of stranded assets must be included in agreements and transition plans.

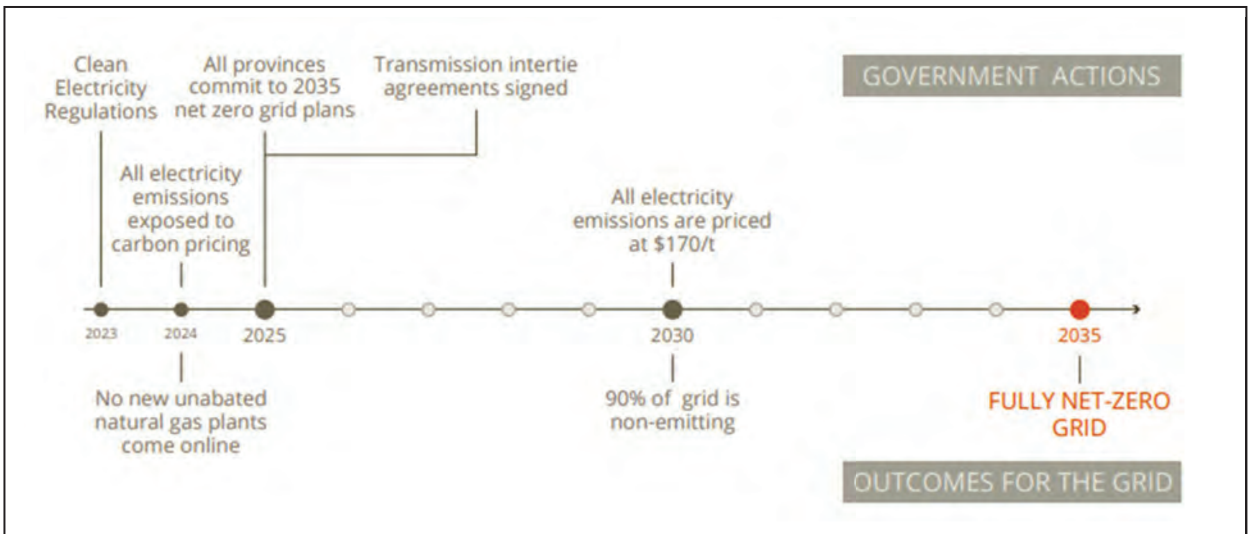

Figure 2. Milestones and timeline for transition to a NZE electricity sector in Canada
Reproduced from "Achieving a Net-Zero Canadian Electricity Grid by 2035". Pembina Institute (16).

The Electricity Supply Sector in Saskatchewan: Current Status and Plans for Transition

In 2021, 25.6 TWh of electricity were supplied in Saskatchewan (17). Fossil fuel combustion accounted for 80% of this electricity (see Figure 3). Eleven percent of the energy mix came from hydro and renewables accounted 6.7% of the total. Imported hydroelectricity from Manitoba provided the remaining 3% of electricity supply. In 2021, 14.9 Mt of CO_2 equivalents were released to the atmosphere from power generation in Saskatchewan. The blended intensity of emissions from the electricity supply sector in Saskatchewan was about 580 g CO_2eq/kWh which was the highest in Canada (17).

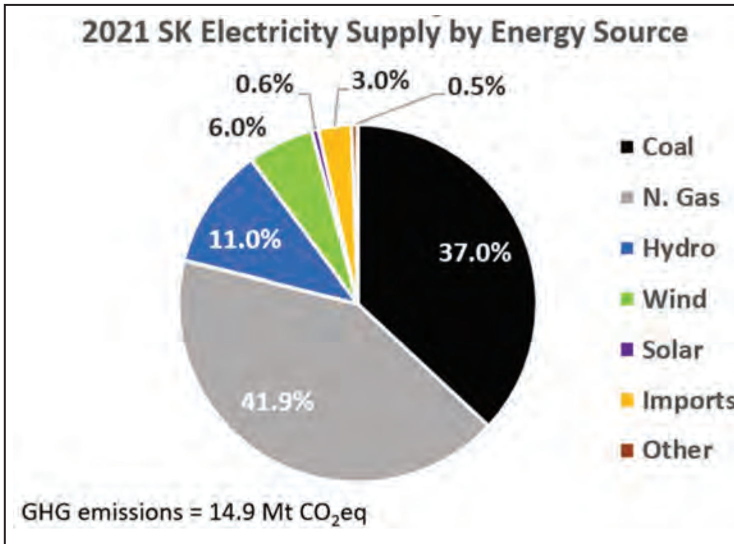

Figure 3. Energy mix for electricity supply in Saskatchewan (17) Imports come from Manitoba hydro.

Unabated coal fired generators will be shut down by 2030 in accordance with federal regulations governing emissions intensity. Figure 4 shows a projection for the year 2030 energy mix for electricity supply in Saskatchewan based on available information from SaskPower and further assumptions as described in the figure legend.

A fleet of 10 natural gas fired stations currently operates in Saskatchewan (17). In addition, the 360 MW gas fired Great Plains Power Station outside of Moose Jaw is under construction (18). Planned upgrades to the Yellowhead and Ermine gas fired stations will add another 92 MW of capacity (18). Beyond these committed projects, a 370 MW gas fired facility is under consideration for the Lanigan area (19) and another unannounced facility of similar size could be added to fully compensate for the closure of coal plants (see Table 1).

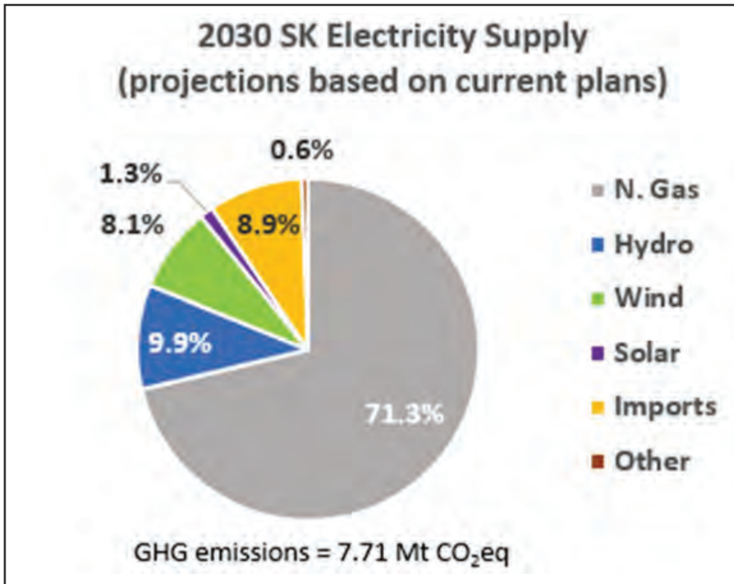

Figure 4. Projected Year 2030 Energy Mix for Electricity Supply in Saskatchewan Based on Current Plans with Assumptions. Projections are based on a shut down of the coal plants and achieving a 50% cut in emissions relative to 2005. The model assumes that the proposed Lanigan facility and another yet to be announced gas plant of similar size are in operation along with existing and under construction gas plants, hydro, wind and solar facilities. Imports are assumed to increase to 8.9% of total supply. On a blended basis the fleet of gas plants are assumed to operate at 69% of capacity with an emissions intensity of 380 g CO_2eq/kWh.

Table 1. Natural Gas Power Stations in Saskatchewan (17)				
Gas Power Station	**Owner**	**Capacity (MW)**	**Opened**	**Details**
In Operation				
Meadow Lake	SaskPower	41	1984	Simple Cycle
Meridian Cogeneration	Canadian Power Holdings	228	1999	Co-gen facility
North Battleford	Northland Power	289	2013	Combined Cycle
Yellowhead	SaskPower	135	2010	Simple cycle 46 MW expansion in 2025
Ermine	SaskPower	90	1975	Simple cycle, upgraded 1999 46 MW expansion in 2025
Landis	SaskPower	78	2009	Simple Cycle
Corey Cogeneration	SaskPower	243	2003	Co-gen facility
Queen Elizabeth	SaskPower	623	1959	Extensive upgrades completed 2016 (Combined Cycle)
Spy Hill	Northland Power	89	2011	Simple Cycle
Chinook	SaskPower	353	2019	Combined Cycle
Totals In Operation		**2169**		
Under construction				
Great Plains	SaskPower	360	2024	Combined Cycle
Ermine expansion	SaskPower	46		Simple cycle
Yellowhead expansion	SaskPower	46		Simple cycle
Future Total		**2621**		
Under Consideration				
Lanigan	*SaskPower*	*370*	2028	*Combined cycle*
(Unannounced)	*SaskPower*	*370*	------	*Combined cycle*
Potential Future Total		***3361***		

Table 2. Recent Major Natural Gas Power Plant Projects in Saskatchewan			
Plant	**Project**	**Completion Date**	**Project Cost ($million)**
North Battleford	New Build NGCC	2013	$416
Queen Elizabeth	Extensive upgrades	2016	$525
Chinook	New Build NGCC	2019	$680
Great Plains	New Build NGCC	2024	$780
Total			**$2,401**

Recent and planned expenditures to expand natural gas generation capacity are summarized in Table 2. With completion of the Great Plains Power Station in 2024 a total of $2.4 billion will have been spent over a span of about 12 years on large projects to upgrade and expand capacity of unabated natural gas power plants in Saskatchewan.

Renewables contributed less than 7% of the energy mix to supply electricity in Saskatchewan in 2021. In addition to existing facilities, a 200 MW wind facility and another 110 MW of solar capacity are presently under construction (18). SaskPower has announced a year 2030 target of achieving a 50% cut in greenhouse gas emissions from the provincial electricity supply sector relative to emissions on record for 2005. This level of ambition is consistent with shut down of the coal plants and an expansion of the current fleet of natural gas plants to include the Great Plains Power Station, the proposed Lanigan facility, and an additional yet to be announced facility of similar size.

Beyond 2030, SaskPower has stated a long-term objective of completing a full transition to a Net Zero electricity system by 2050. Presumably natural gas plants would be shut down on an end-of-life basis and would be replaced by renewables plus other zero or very low emissions options such as small modular nuclear power plants.

Net Zero 2035 Compatible Scenarios for Transitioning Saskatchewan's Electricity Supply Sector

Clearly, current plans to transition electricity supply in Saskatchewan are not compatible with the federal government's national target of a Net Zero 2035 electricity system. While the details of the incoming CERs have yet to be announced, new unabated gas plants would not be permitted to operate as of Jan 1, 2035. As such, for these facilities to be viable, the design and costing must include carbon capture and storage technology that would be operational prior to 2035. Existing facilities will be subject to carbon pricing as defined by the CERs. The consumer carbon price applied to consumption of fossil fuel is scheduled to escalate to $170 mt CO_2 by 2030. Under the CERs, beginning in 2035 with application of the full consumer carbon price, unabated gas plants become uneconomic to operate as providers of bulk baseload power.

In Saskatchewan, the economics of a year 2035 transition to a NZE electricity supply are complicated by numerous factors including the sunk cost into expanding the capacity of natural gas generators, the designed life span of these facilities, and offtake agreements with co-gen facilities and privately held generators. However, the challenge of dealing with existing assets cannot lead to compromises that would undermine Canada's commitment to a 100% clean electricity sector by 2035.

The Canada Energy Regulator - Net Zero emissions Base Scenario (NZ) and Saskatchewan's Electricity Generation Sector

Recently, the Canada Energy Regulator published a set of scenarios with year 2035 Net Zero or Net Negative emissions outcomes (20). Modelling was based on least-costing of options for generating electricity with assumptions as to carbon pricing and standards imposed under the proposed Clean Electricity Regulations. The models assumed that necessary agreements on interties are in place and allowed for an expansion of inter-provincial and regional transmission capacity. In the model of the NZ base scenario, all technologies were allowed except for BECCS.

The Canada Energy Regulator NZ base scenario model projected an energy mix for electricity supply in Saskatchewan that is radically different from current projections (Figure 5). Other than the one gas plant under construction, no new gas plants would be built. The contribution of unabated natural gas drops to 20% of the total energy mix to generate electricity. Saskatchewan would become a renewable energy powerhouse, with about 6,000 MW (10-fold increase) of new build wind facilities plus 1,300 MW of new build solar. The NZ base case model predicted that near zero emissions sources account for nearly 80% of electricity generated with a corresponding drop of 86% in emissions relative to the 2005 reference. The substantial increase in renewable power generation would be managed and balanced via agreements on interties which help control the flow of electricity between hydro and renewables rich regions of interconnected grids. Under this scenario, Saskatchewan will have an excess electricity generation capacity from unabated gas plants. On a blended basis, the entire fleet of Saskatchewan's gas fired generation would be operating at 25% of capacity. It is likely that multiple gas generators would be decommissioned prior to scheduled end-of-life. Overall, the NZ scenario takes full advantage of the renewables resource potential of Saskatchewan and integrates this potential with existing large-scale hydro capacity in other regions.

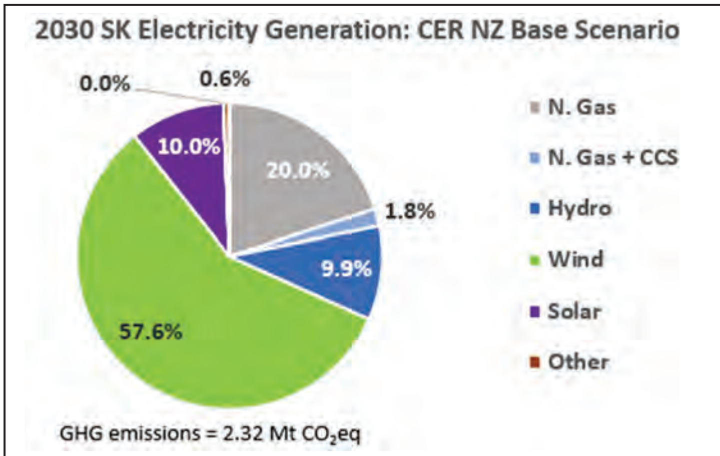

Figure 5. Canadian Energy Regulator Projected Year 2030 Energy Mix for Electricity Generation in Saskatchewan (Net Zero emissions Base Scenario). In the model, natural gas (with and without CCS), hydro, renewables, nuclear, electricity storage and inter-provincial transmission were allowed as available technolgies. GHG emissions from electricity generation are cut by 86% and the system is set up for further cuts as required to arrive at near zero emissions by 2035.

Beyond 2030, the Canada Energy Regulator NZ base scenario model projects emissions intensity of electricity generation in Saskatchewan to decline with progressive shut down of unabated gas plants while other existing gas plants are retrofit with Carbon Capture and Storage (CCS). Renewables and other zero emissions options enter the electricity generation energy mix on a least-cost basis. In 2050, wind and solar account for 82% of the energy mix (see Figure 6). Natural gas continues to contribute, accounting for 12% of the energy mix; however, over 80% of natural gas generation would be equipped with CCS to limit emissions to near zero levels. Variable output unabated natural gas "peaker" plants have a role in grid balancing but account for only 2% of the 2050 energy mix.

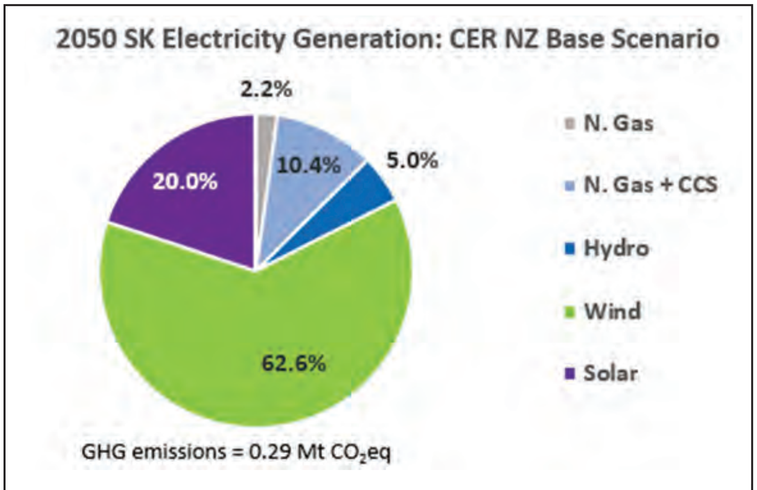

Figure 6. Canadian Energy Regulator Projected Year 2050 Energy Mix for Electricity Generation in Saskatchewan (Net Zero Emission Base Scenario). By mid-century 98% of the electricity generated in Saskatchewan comes from zero or near zero emissions sources. Potentially excess production of electricity from renewables could be used to power negative emissions Direct Air Capture or to produce green hydrogen by electrolysis.

Nuclear power does not compete with other options on a cost basis. In the longer term, depending upon maturity and cost, battery and other storage technologies may play an important role in Saskatchewan's electricity generation mix.

A continued expansion of renewables has considerable potential to provide an excess of zero emissions electricity on an intermittent basis. When available, this electricity could be used to power negative emissions Direct Air Capture (DAC) or electrolysis to produce green hydrogen. Under the global Net Zero pathway, the IEA projects 3,670 GW of electrolyser capacity will be in place by 2050. Green hydrogen has the potential to replace natural gas using existing delivery infrastructure for multiple applications such as residential heating and industrial thermal energy needs.

The modelling work of Dolter and Rivers (13) indicates an optimal installed wind generation capacity for Saskatchewan of 27,600 MW when interprovincial transmission is allowed. The suggested 27,600 MW of wind generation capacity is 4-fold greater than the current total installed capacity to generate electricity from all energy sources in the province. For reference, SaskPower installed 385 MW of new wind power capacity in the 2021-2022 fiscal year – which suggests SaskPower should increase its ambition for new wind energy installations by an order of magnitude. Under a zero emissions scenario, the Dolter and Rivers modelling projects a national energy mix of 53% hydro, 35% wind, and 12% nuclear for the generation of electricity. In this model, new build nuclear (including small modular reactors), grid-scale solar, and other technologies are not cost-competitive with wind farms. BECCS was not considered in this modelling work. Wind generation would be concentrated in southern Saskatchewan along with greatly expanded interprovincial electricity transmissions lines to both import and export electricity.

The Canada Energy Regulator – BECCS Scenario and Saskatchewan's Electricity Generation Sector

The Canada Energy Regulator modelled 6 scenarios of transition based on alternate underlying assumptions. The BECCS scenario is of particular relevance given the potential for implementation in Saskatchewan. Unlike the NZ model discussed immediately above, BECCS was modelled as a viable technology for electricity generation. In the model, BECCS facilities were credited per unit of atmospheric CO_2 withdrawal using the carbon price that applies to emissions. The Western Canadian Sedimentary Basin is an ideal geological formation for the storage of captured carbon; therefore, BECCS implementation is restricted to Alberta and Saskatchewan. Finally, the BECCS model was limited to 6 GW maximum installed capacity based on a reasonable limitation for the annual supply of sustainably sourced biomass. All other assumptions in the NZ base scenario were maintained.

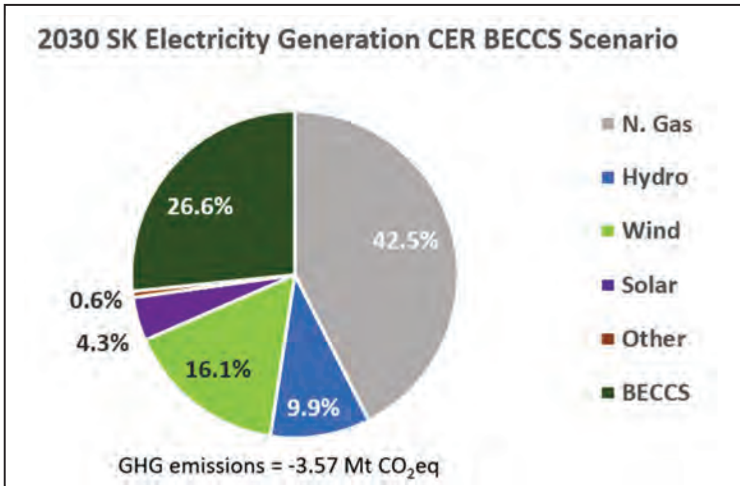

Figure 7. Projected Energy Mix for Year 2030 Electricity Generation in Saskatchewan Based on the Canadian Energy Regulator BECCS Scenario. Retro-fit of coal plants or new build BECCS facilities are commissioned by 2030. BECCS atmospheric CO_2 withdrawal offsets continued emissions from unabated natural gas plants such that these facilities can continue to operate past 2035. This projected energy mix would pull 3.6 million tonnes per year of CO_2 from the atmosphere. Going forward, as the gas plants reach end-of-life and are replaced by zero emissions options, the magnitude of net negative emissions increases.

The revenue potential of atmospheric CO_2 withdrawal pulls BECCS into the least-cost energy mix up to the limit of 6 GW capacity. Potentially, existing coal fired generators in Saskatchewan could be retrofitted to become negative emissions BECCS power plants by 2030. After retrofit, the combined capacity of the three coal plants would approximate 1 GW and would be well within the limit imposed by CER model. The magnitude of atmospheric CO_2 withdrawal would markedly exceed total emissions from existing and under construction natural gas plants (see Figure 7). Assuming a fleet averaging approach to calculating net emissions, offsets from BECCS power plants would allow for continued operation of unabated natural gas facilities in Saskatchewan past 2035. This outcome would address the issue of stranding costly natural gas assets. Going forward, renewables, other zero-emissions options, and, potentially, new build BECCS plants, would replace end-of-life gas plants. Industry looking to minimize scope 2 emissions (emissions from electricity and other consumables used in the manufacture of products) would welcome a supply of negative emissions electricity. Local provision and export of negative emissions electricity would be valued by industry and could provide the foundation for economic development in Saskatchewan as the world transitions to a new low carbon reality.

Economics of Future Scenarios for Electricity Supply in Saskatchewan

Wind Farms

The Levelized Cost of Electricity (LCOE) refers to the revenues required per unit of electricity sold over a specified period (usually the anticipated lifespan of the generation equipment) to cover the costs of building and operating the facility. In recent years, with advances in the technology and broader application, the LCOE for unsubsidized onshore wind farms has dropped dramatically. Wind is now the lowest cost option for generating electricity. In 2021, the LCOE for onshore wind was in the range of $26-$50 USD/MWh (21). In comparison, the LCOE for an unabated natural gas combined cycle plant ranges from $45-$74 USD/MWh (21).

In Saskatchewan, given the wind resource potential of the province, electricity costs to consumers and industry can be minimized through optimal grid penetration by wind farms. However, in the absence of interprovincial transmission capacity, interties, and balancing by large scale hydro, potential grid penetration by wind is limited and Saskatchewan would likely continue to rely on other dispatchable energy sources for the bulk of its electricity supply. With modernization of the grid and expanded interprovincial transmission capacity, the potential for wind power in Saskatchewan increases by an order of magnitude. Potentially, Saskatchewan's electricity supply needs could be met by wind energy balanced by distant large-scale hydro with minimal intermittent need for localized natural gas "peaker" generation plants. Under a scenario of a dramatic expansion of wind farms within Saskatchewan, excess electricity from renewables could be exported, or converted to other zero emissions energy carriers such as hydrogen.

BECCS

In 2018, the International CCS Knowledge Center published a feasibility study on retrofitting the coal fired Shand Power Station in Saskatchewan to carbon capture and storage (22). The study was based on learnings from the world's first commercial scale retrofit of a solid fuel power generator at unit 3 (BD3) of the nearby Boundary Dam coal fired power plant. Based on knowledge gained from BD3, the study anticipates a 67% saving in capital costs for retrofitting the Shand 305 MW power station with second generation CCS technology. Costs of CO_2 capture were estimated at $45USD/t and the plant could operate at up to 95% capture efficiency. Fuel switching from coal to biomass along with the CCS retrofit would convert Shand to a negative emissions facility. The Shand Feasibility Study provides sufficient details for modelling the LCOE for this option of electricity generation.

In the Canada Energy Regulator's BECCS scenario, negative emissions facilities are paid per tonne of atmospheric CO2 withdrawal and this payment could mirror the emissions tax applied to consumer use of fossil fuel products. Figure 8 shows the impact of carbon pricing on the LCOE for three options of comparable sized thermal power plants. Under the proposed federal system, carbon pricing escalates to $170/t by 2030. Direct application of this price to emissions from a new build natural gas combined cycle power plant would double its LCOE. In comparison, carbon pricing would result in a small increase in electricity costs for a CCS retrofitted plant with continued use of coal (such as BD3). In the absence of carbon pricing, the high cost of western Canadian wood pellets drives up the cost of electricity coming from a BECCS retrofitted thermal power plant. However, if the utility is paid $70 per tonne of CO_2 withdrawn from the atmosphere, the cost of electricity is comparable to other options. At higher carbon prices, retrofit of an existing coal fired power plant to CCS with fuel switching to biomass generates cost-advantageous electricity. Potentially, production credits can be used to control costs such that consumers and industry can be supplied with low-cost negative emissions electricity.

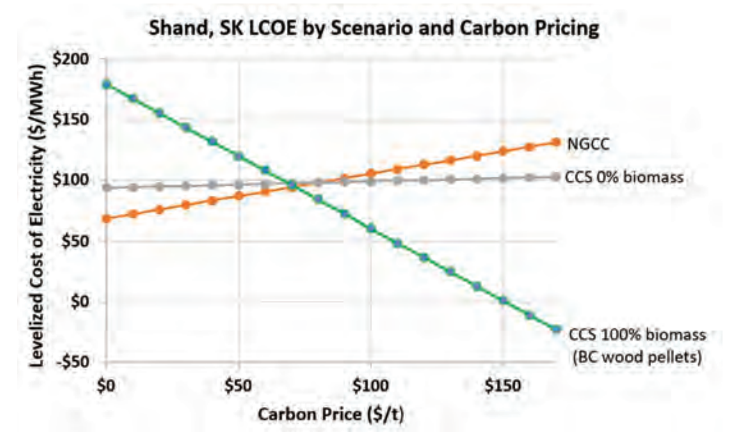

Figure 8. Levelized Cost of Electricity (LCOE) of three similar sized power plant options for the SaskPower Shand facility. LCOE calculator kindly provided by Dr. Brett Dolter (University of Regina). Calculator was based on the Shand feasibility study completed by the International CCS Knowledge Center for retrofitting the Shand thermal power plant to second generation CCS (15). Grey line shows the impact of carbon pricing on the LCOE of the converted plant with continued use of coal. Orange line shows LCOE of similar sized new build natural gas combined cycle plant. Green line shows the LCOE with a negative emissions CCS retrofit of Shand and 100% fuel switching to wood pellets. Delivered cost of wood pellets set to $9.47/GJ (23). This option assumes the utility is paid the equivalent of the carbon price for atmospheric CO_2 withdrawal.

The cost for a complete CCS retrofit of the three coal fired power plants in Saskatchewan, along with the costs of building pipelines and injection sites for the transport and geological storage of captured carbon, would likely exceed $5 billion. Further studies are needed as to the suitability of each coal fired unit for retrofit to CCS and there may be a case for a new build BECCS facility when compared to the costs of retrofitting an existing plant.

The high upfront costs of installing CCS equipment will be a hurdle to BECCS implementation in Saskatchewan. However, in 2022 the Government of Canada annouced an investment tax credit for Carbon Capture, Utilization and Storage projects designed to cover up to 60% of the cost of carbon capture equipment. To incentivize rapid uptake, as of 2031, the tax credit will be reduced by half.

To be viable, BECCS requires a meaningful production tax credit. In the USA, the Inflation Reduction Act increased the 45Q production tax credit to $85 USD/metric tonne of atmospheric CO_2 withdrawal (24). If Canada were to match this incentive, (i.e. $113 Can/tonne), BECCS is not only viable, it is cost advantageous to any other option to produce electricity. The cost of negative emissions electricity from a BECCS retrofit of the Shand power plant with a $113/t production tax credit in place would be about $48/MWh. This LCOE equates to a 56% saving in the cost of electricity to consumers and industry when compared to a modern natural gas combined cycle power plant subject to the same carbon pricing.

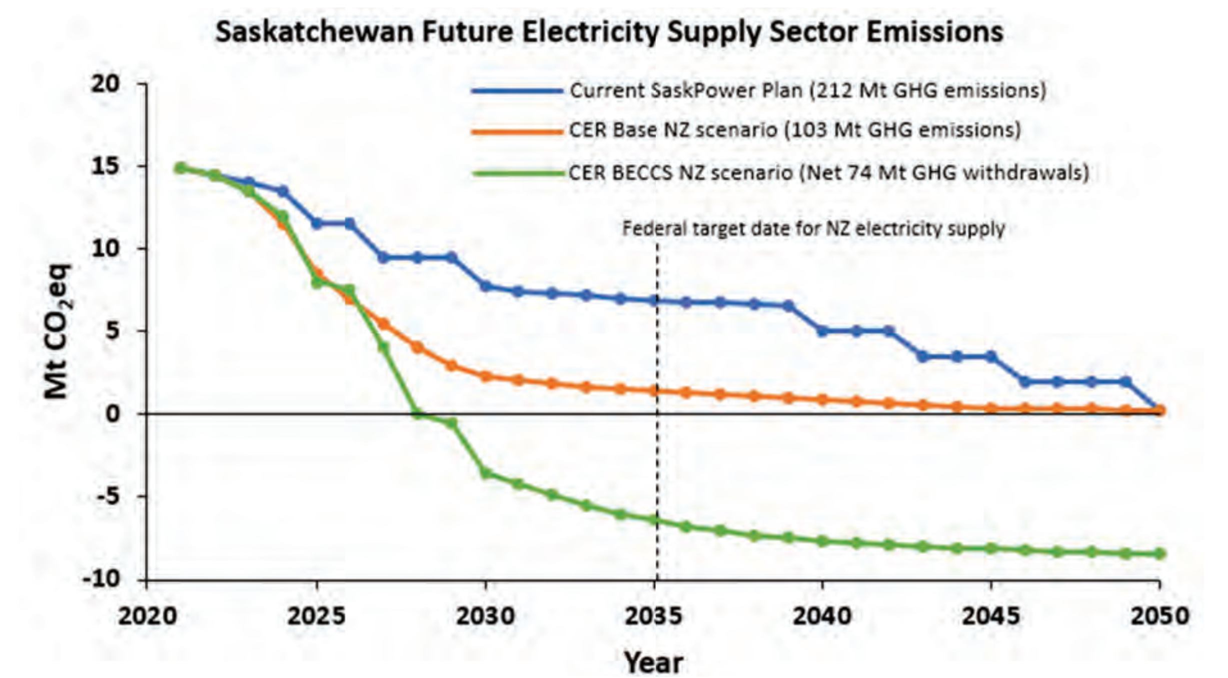

Figure 9. Projected Emissions from Saskatchewan Electricity Generation Sector from 2021 to 2050. The current SaskPower plan is based on going forward with the proposed Lanigan gas plant plus an additional similar gas fired unit. Gas plants would continue operation to prescribed end-of-life and would be replaced by small modular nuclear reactors, renewables, and other zero emissions options. The Canadian Energy Regulator's Base Net Zero emissions scenario assumes no further new build gas plants, a rapid expansion of renewables, and progressive turn down of gas plants. Electricity flows between hydro and renewable rich provinces through new build transmissions lines and intertie agreements. With the BECCS scenario, BECCS is allowed as an option for power generation. BECCS facilities are paid per tonne of atmospheric CO_2 withdrawal. Carbon dioxide withdrawal via BECCS offsets emissions from gas plants such that these facilities continue to operate to end-of-life. Gas plants are eventually replaced with zero emissions options.

Summary and Conclusions

Despite the challenges, Canada is well positioned to complete a timely transition to a national clean electricity sector. Existing zero emissions large-scale hydro facilities provide the bulk of baseload power in many regions of the country. In addition, Alberta and Saskatchewan have considerable untapped wind and solar potential along with a world class resource for the geological storage of captured carbon. Large volumes of sustainably sourced waste biomass from forestry, forest management, agriculture and municipal sources are available on an annual basis.

To complete the transition to a clean electricity system by 2035, Canada must build a network of interprovincial transmission lines and interties such that power can flow between distant hydro rich and renewables rich regions of the country. Alberta and Saskatchewan will be the principal benefactors of this infrastructure build in that these provinces will no longer be isolated from existing large-scale hydropower and the potential for renewables and BECCS in these provinces can be fully realized. The upcoming Clean Electricity Regulations will provide the necessary policy framework to drive the transition to a clean electricity sector by 2035.

In 2023, the Government of Saskatchewan will be faced with a choice to either accept or challenge the jurisdictional authority of the federal government's Clean Electricity Regulations. Court challenges to the CERs will delay and may well undermine efforts to build consensus among levels of government and stakeholders as to installation of interprovincial and interregional transmission capacity, grid modernization, storage capacity, and critical intertie agreements. A failure to execute means a continuation of the status quo and a failure to complete a timely transition to a Net Zero electricity system.

Rather than opposing the CERs, the Government of Saskatchewan can enter into good-faith negotiations within the Pan-Canadian Grid Council to build interprovincial transmission capacity and work toward signing critical intertie agreements that would facilitate the flow of power between hydro rich and renewables rich regions. The issue of stranded natural gas assets would be part of the negotiations. Conceivably, SaskPower could embark on feasibility studies aligned with the NZ base scenario and the BECCS Scenario put forward by the Canada Energy Regulator. With transmission capacity in place, Saskatchewan (and Canada) would be positioned to take full advantage of the potential for low-cost renewables power generation. If Canada were to match the 45Q production tax credit in the USA, the economics for BECCS implementation become compelling and would incentivize a timely transition of Canada's electricity sector to net negative emissions. The location of the Western Canada Sedimentary Basin favours Saskatchewan and Alberta for implementation of BECCS. Saskatchewan is ideally positioned to become a world leader in building a cost-effective negative emissions electricity sector. Local supply, and possibly export of low-cost negative emissions electricity would be the foundation for attracting industry and economic prosperity in Saskatchewan.

The reality of damage caused by severe weather events directly related to a changing climate is reported in daily newscasts around the world. There is no longer any luxury of time to waste on political squabbling over jurisdiction rights and populist rhetoric that often contradicts science-based facts and the societal benefits of taking effective action to achieve ambitious targets to cut emissions.

Simply put, it is in the best interests of Saskatchewan to accept the upcoming federal Clean Electricity Regulations and to enter a good-faith partnership with the federal government, other provinces and territories, and other stakeholders toward developing a Net Zero or a Net Negative Emissions electricity system by 2035.

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Energy Policy 113 (2018) 135–148

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

The cost of decarbonizing the Canadian electricity system

Brett Dolter[a,*], Nicholas Rivers[b]

[a] Institute of the Environment, University of Ottawa, Canada
[b] Public and International Affairs, Institute of the Environment, University of Ottawa, Canada

ARTICLE INFO

Keywords:
Electricity
Greenhouse gas emissions
Linear programming
Canada
Renewable energy
Transmission

ABSTRACT

Canada's electricity sector is predominantly low-carbon, but includes coal, natural gas, and diesel fuelled power plants. We use a new linear programming optimization model to identify least-cost pathways to decarbonize Canada's electricity sector. We co-optimize investments in new generation, storage and transmission capacity, and the hourly dispatch of available assets over the course of a year. Our model includes hourly wind speed data for 2281 locations in Canada, hourly solar irradiation data from 199 Canadian meteorological stations, hourly demand data for each province, and inter- and intra-provincial transmission line data. We model the capacity of hydropower plants to store potential energy and respond to variations in renewable energy output and demand. We find that new transmission connections between provinces and a substantial expansion of wind power in high wind locations such as southern Saskatchewan and Alberta would allow Canada to reduce electricity sector emissions at the lowest cost. We find that hydropower plants and inter-provincial trade can provide important balancing services that allow for greater integration of variable wind power. We test the impact of carbon pricing on Canada's optimal electricity system and find that prices of \$80/tonne CO_2e render the majority of Canada's coal-fired plants uneconomic.

1. Introduction

With the ratification of the Paris Agreement, the world has committed to "holding the increase in the global average temperature to well below 2 °C above pre-industrial levels" (United Nations Framework Convention on Climate Change UNFCCC, 2015: 2). By some estimates, meeting the 2 °C target will require global per capita greenhouse gas (GHG) emissions of 1.7 tonnes carbon dioxide equivalent (CO_2e) per person by 2050 (Bataille et al., 2015). As context, Canada's per capita GHG emissions were 20.6 tonnes CO2e in 2014 (Environment and Climate Change Canada, 2016).

In this paper, we ask: how much will it cost to decarbonize the Canadian electricity system? Canada starts from an advantageous position. In 2014, Canada generated 78.4% of its electricity using low-carbon technologies such as hydropower plants (60.3%), nuclear power plants (16.2%), and wind turbines (1.8%) (Statistics Canada, 2016 CANSIM 127-0007).[1] The remainder came largely from coal and natural gas power plants. Canadian fossil fuel electricity plants emitted 79 Megatonnes (Mt) CO_2e in 2015, which accounted for 10.9% of Canada's 722 Mt CO_2e GHG emissions total (Environment and Climate Change Canada, 2017).

In our analysis we pay particular attention to the potential for Canada to develop wind and solar energy. Canada has several regions where annual average wind speeds at 50 m (m) elevation reach 7 m/sec (m/s) or better, including the southern Plains of Alberta and Saskatchewan, southern Ontario, and northern Quebec (Global Modelling and Assimilation Office GMAO, 2016; see Fig. 1a). Solar photovoltaic installations can achieve annual capacity factors as high as 16% in sunny areas such as southeast Saskatchewan (MSC & Meteorological Service of Canada MSC and Natural Research Council NRC, 2010; Fig. 1 b). Canada is also the second largest hydropower producer in the world, behind only China and on par with Brazil (Natural Resources Canada, 2016). Canada's hydropower reservoirs can provide balancing services to allow higher integration of wind and solar onto the electricity grid.

Fig. 1a Source: Global Modelling and Assimilation Office (Global Modelling and Assimilation Office GMAO) (2016); author's calculations. Fig. 1b Source: Meteorological Service of Canada (MSC) and Natural Research Council (Meteorological Service of Canada MSC and Natural Research Council NRC) (2010); author's calculations.

We also model whether it is beneficial to build new high-voltage transmission between Canadian provinces. Provinces have different electricity generation profiles (Fig. 2). Hydropower plants are an important source of electricity generation in Quebec, Newfoundland and

* Correspondence to: Institute of the Environment, University of Ottawa, 1 Stewart Street (301), Ottawa, ON K1N 6N5.
E-mail address: brett.dolter@gmail.com (B. Dolter).

[1] Note that these Statistics Canada numbers are known to underestimate renewable energy production. For example, as of December 2016, the Independent Electricity System Operation (IESO) in the province of Ontario had 4514 Megawatts (MW) of wind power capacity and 2206 MW of solar power capacity under contract (IESO, 2016). By contrast, Statistics Canada (2016) CANSIM 127-0009 reports 2762 MW of wind capacity and 172 MW of solar capacity in Ontario for the year ending 2015. The discrepancy arises because Statistics Canada does not survey facilities below a certain capacity threshold, and neither the IESO or Statistics Canada report generation from "embedded" wind and solar facilities connected to local distribution systems.

http://dx.doi.org/10.1016/j.enpol.2017.10.040
Received 4 February 2017; Received in revised form 10 October 2017; Accepted 20 October 2017

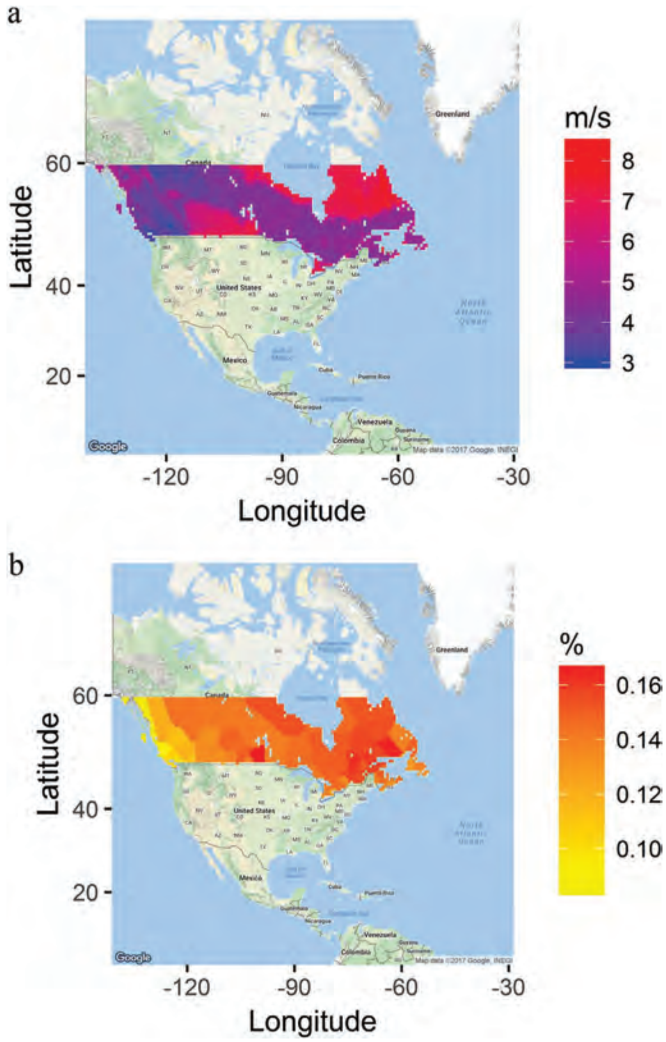

Fig. 1. a Wind speed by MERRA grid cell. b Solar capacity factors by MERRA grid cell.

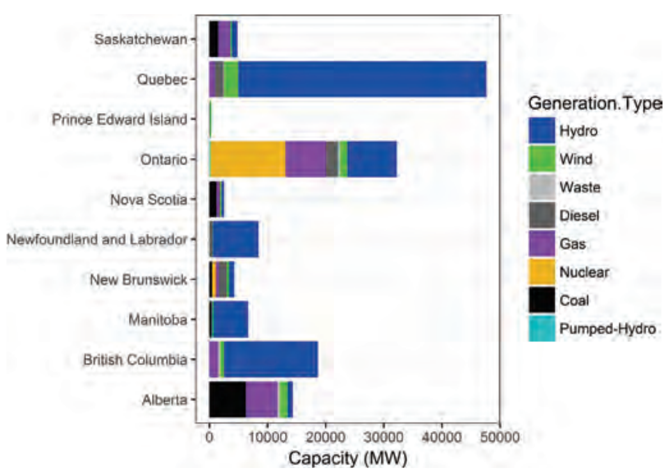

Fig. 2. Canadian electricity generation capacity by Province.[2]

Labrador, Manitoba, and British Columbia. Provinces relying on coal and natural gas fired power plants include Saskatchewan, Nova Scotia, New Brunswick, and Alberta. Geographically, each of the fossil-fuel powered provinces is adjacent to a hydropower province. However, the existing transmission network allows only limited east-west inter-provincial electricity trade. We test whether strengthened transmission connections between provinces can lower the cost of reducing electricity sector GHG emissions in Canada.

Other recent studies of decarbonizing the Canadian electricity sector include the Trottier Energy Futures Project TEFP (2016), General Electric International GE (2016), and Ibanez and Zinaman (2016).

The Trottier Energy Futures Project (TEFP) (2016) study uses a proprietary version of the *North American Times Energy Model (NATEM)* to identify 11 scenarios for lowering GHG emissions in Canada. The NATEM model represents the electricity sector spatially at the provincial scale and temporally using 16 time-slices to represent the variation of electricity demand (ESMIA, 2017). The Trottier Energy Futures Project (TEFP) (2016) concludes that decarbonizing the electricity sector is an important measure to facilitate GHG emissions reduction in Canada.

The GE (2016) study uses a "heuristic generation expansion planning approach" to understand the potential for integrating wind energy into the Canadian electricity system (p. 23). The GE (2016) study finds that it is technically feasible for wind energy to make up 35% of Canadian electricity generation. This is achieved by expanding wind power capacity to 65 Gigawatts (GW) in Canada with concentrations of 15 GW or more in Ontario, Quebec, and Alberta. In our results, we find similar potential for wind energy, but with a different provincial distribution of installations. The GE (2016) study also identifies one potential set of transmission lines that could be built to aid wind energy integration. Our study uses an optimization approach to assess the value of constructing additional transmission links.

The analysis by Ibanez and Zinaman (2016) jointly optimizes Canadian and United States (US) electricity futures using the NREL *Regional Energy Deployment System (ReEDs)* model. This is a useful approach since there are greater transmission connections north-south from Canada to the United States than there are east-west between provinces within Canada. We model the interdependent nature of the Canadian and US electricity system by including hourly export data from Canadian provinces to the US. This simplification means that we do not co-optimize investments in generation and transmission capacity between Canada and the United States. Instead we focus on actions Canada can take within its borders to decarbonize and optimize electricity supply. The NREL ReEDs model contains 47 wind and solar power resource regions within Canada and 17 time-slices to represent spatial and temporal variation in renewable energy supply and electricity demand (Ibanez and Zinaman, 2016).

Our contribution to the literature is threefold. First, we model the Canadian electricity system with much greater spatial and temporal resolution than previous studies. We include hourly demand data over the course of a year for each province (8760 hourly time steps), hourly wind resource data for 2281 grid cells south of 60° latitude in Canada, and hourly solar resource data for 199 meteorological stations south of 60° latitude. In contrast, the NATEM (Trottier Energy Futures Project (TEFP), 2016) and ReEDS (Ibanez and Zinaman, 2016) models use representative temporal snapshots of electrical grid operation (called time-slices), and lower spatial resolution for their wind and solar data.

We use the high resolution spatial and temporal data to co-optimize investments in new generation with the hourly dispatch of available generation assets over the course of a year. The hourly wind and solar resource data in our model allows us to account for the variability of electricity supplied by renewable energy. Our co-optimization approach is most similar to MacDonald et al. (2016) who evaluate the potential for greater renewable energy integration in the United States. MacDonald et al. (2016) find that increased investment in wind and solar power could allow the United States to reduce electricity sector GHG emissions by 80% below 1990 levels without increasing electricity costs. We find that wind energy is a low-cost means of reducing GHG emissions in Canada. At a carbon price of \$200/tCO_2, investments in wind can achieve GHG reductions of 83–87% below 2025 reference scenario emissions and would increase average electricity costs by \$12 to \$13/Megawatt-hour (MWh). In these low-carbon scenarios, wind energy meets 30–35% of electricity demand despite its variability.

Our second contribution to the literature is evaluating the desirability

[2] This figures shows existing Canadian electricity capacity, minus expected retirements by 2025. Data is collected from various sources outlined in the Supplementary Information (SI) document that accompanies this paper.

of investing in transmission and storage technologies. Transmission lines and energy storage technologies can be thought of as substitute options for balancing the variability of renewable energy. We test which is most important in an optimized Canadian electricity system. We find that new inter-provincial transmission lines can reduce the cost of achieving a zero-carbon electricity system by 26% relative to scenarios where new inter-provincial transmission is not allowed. We also find that transmission lines obviate the need for energy storage in Canada. This finding mirrors MacDonald et al. (2016) who concluded that high-voltage direct current (HVDC) transmission lines allowed for high levels of renewable penetration without energy storage. In a sensitivity analysis, we also find that if capital costs for HVDC transmission lines are much higher than expected, the optimal level of investment in transmission is decreased, and the optimal level of investment in energy storage is increased.

Third, we offer insights into the impact of proposed Canadian climate policies. The Canadian government has recently announced plans for a national carbon price that starts at \$10/tonne carbon dioxide equivalent (CO_2e) and increases to \$50/tonne by 2022 (Prime Minister of Canada, 2016). We consider the impact of carbon pricing on the optimal generation mix of the Canadian electricity sector. We find that, barring complementary policies, carbon prices must rise above \$50/tonne CO_2e to achieve significant decarbonization in Canada's electricity sector. In our modelled scenarios, we find that carbon prices of \$80/tonne CO_2e render Canada's remaining coal-fired plants uneconomical. We also find that some natural gas combined cycle capacity remains optimal even at carbon prices of \$450/tonne CO_2e.

This paper proceeds as follows. In the next section, we describe our modelling approach and data sources. We then present the results of our analysis. In the final section, we discuss the policy implications of our results and conclude.

2. Methodology and data

2.1. Model design

We simulate the Canadian electricity system using a new a linear programming optimization model which co-optimizes investment in new electricity generation, transmission, and storage facilities and the hourly dispatch of these facilities to meet electricity demand. A distinguishing feature of the model is its high geographic and temporal resolution, which is especially relevant for intermittent wind and solar technologies.

We use this model to minimize the total annual cost of operating the Canadian electricity system, which includes annualized capital costs (CC), fixed operations and maintenance costs (FOM), variable operations and maintenance costs (VOM), fuel costs (FC), and carbon pricing costs (CP) (Eq. (1)).[3]

$$Totalcost = CC + FC + FOM + VOM + CP. \tag{1}$$

The model minimizes annual electricity system costs by selecting capital investments in electricity generation technologies, storage facilities, and transmission lines, as well as the hourly dispatch of available assets over the course of a year (8760 h).

In this section, we provide a qualitative description of the model. A complete mathematical description of the model and the data used to parametrize the model is available in the Supplementary Information (SI) document.

2.2. Constraints

To give shape to the problem of planning Canada's electricity future, our model requires constraints. Important constraints include:

[3] In some of our scenarios, we motivate GHG emissions reductions by imposing a price on carbon dioxide emissions. Carbon pricing cost (CP) is a function of the electricity supplied by GHG emitting thermal generation technologies (tp) in each hour (h), the carbon price (cprice), the GHG content of fuel (fuel_CO2), and the fuel efficiency (η_{tp}) of each generation technology (Eq. (2)).

$$CP = \sum_{h,tp} supply_{h,tp} \times cprice \times fuel\_CO2_{tp} \times 3.6 \times \frac{1}{\eta_{tp}}. \tag{2}$$

- Electricity supply must be equal to or greater than demand in each hour and balancing area;[4]
- Hourly dispatch from electricity generation assets must be less than or equal to installed capacity;
- Hourly electricity transmission between balancing areas must be less than or equal to transmission capacity;
- The density of wind installations in each grid cell must be less than 2 MW per kilometer-squared (km^2) (drawn from GE, 2016). We also exclude lakes and rivers from wind and solar development;
- The density of solar installations in each grid cell must be less than 31.3 MW per km^2 (drawn from Ong et al., 2013).

We include operational constraints to control the speed at which dispatchable generation facilities can ramp up and down.[5] We also set minimum and maximum annual capacity factors to ensure that generating capacity operates within an economically viable and technically feasible range (Table 1). Minimum capacity factors represent the economic reality that a plant will have to run for a minimum amount during a year to justify ongoing staffing and operation of the facility. Maximum capacity factors represent the technical constraint that plants will require shutdowns on occasion and do not operate at 100% capacity throughout the course of a year.[6] These constraints are required because we allow investment into generation capacity on a continuous scale and do not use an integer programming investment modelling approach or unit commitment dispatch modelling approach. A full account of the constraints in our model is included in the SI.

2.3. Wind and solar energy modelling

Our model includes hourly wind power capacity factor data for 2281 grid cells south of the 60th parallel of latitude in Canada (each grid cell is one-half degree by two-thirds of a degree). We obtain hourly wind speed data for 2014 from the *Modern-Era Retrospective analysis for Research and Applications* (MERRA) dataset (Global Modelling and Assimilation Office GMAO, 2016).[7] We translate this wind speed data into hourly capacity factors assuming a 3 MW wind turbine with 80-m hub height and 110-m rotor swept diameter (see Supplementary Information (SI) for details on construction of power curve). Hourly wind energy production in the model is the product of wind power capacity installed in a MERRA grid cell and the capacity factor in that grid cell and hour.

Our model also includes hourly solar capacity factor data for each MERRA grid cell. We first obtain solar irradiation, temperature and snowcover data for 199 meteorological stations south of 60° latitude from the *Canadian Weather for Energy Calculations* (CWEC) dataset (MSC & Meteorological Service of Canada MSC and Natural Research Council NRC, 2010). We then use this data to calculate hourly capacity factor values for each CWEC meteorological station (see SI for details). To match the spatial distribution of our wind data, we assign each MERRA grid cell the hourly solar capacity factor data of the nearest CWEC meteorological station. Like wind energy production, solar energy produced in each hour is the product of installed solar capacity in a given MERRA grid cell and the hourly capacity factor for that cell.

Wind and solar energy in our model is non-dispatchable. Rather, the

[4] Note that we do not model the requirement for surplus reserve capacity to be maintained to provide backup in case of unexpected outages or increases in demand.

[5] Note that we do not model discrete electricity generation units and so all available capacity can ramp up and down at the same rate.

[6] Note that without maximum capacity factors in our model, nuclear and combined cycle gas plants often register 100% capacity utilization. This unrealistic operating range allows the model to invest less in capacity and reduces total costs by 1.4 – 5.2% depending on the scenario. In general, removing the minimum or maximum capacity factor constraints reduces total cost. The relative importance of each constraint varies by scenario.

[7] MERRA grid cells vary in east-west width from 48.6 km at the 49th parallel to 37 km at the 60th parallel and have a north-south height of approximately 55.5 km.

Table 1
Cost and operating characteristics of modelled generation and storage technologies.

Technology	Capital Cost ($CAD/kw)	Amortization (yrs)	Annualized Capital Cost ($CAD/MW)	Efficiency (%)	Variable O & M ($/MWh)	Fixed O & M ($/MW/yr)	Capacity Factor (%)	
							Min.	Max.
Coal	$3836	25	$440,647	39.0%	$4.48	$76,723	40%	93%
Diesel	$831	25	$95,474	39.0%	$19.18	$19,181	10%	95%
Natural Gas Combined Cycle	$1471	20	$178,355	50.9%	$3.52	$7480	40%	70%
Natural Gas Simple Cycle	$1151	20	$139,582	28.0%	$7.80	$19,181	5%	20%
Nuclear	$8695	25	$998,801	32.7%	$0.80	$172,626	40%	90%
Pumped Hydro	$2500	25	$287,169	75.0%	–	$18,000	–	–
Solar	$1790	20	$205,635	–	–	$14,705	–	–
Waste	NA	NA	NA	39.0%	$100.00	$100,000	40%	80%
Wind	$1598	20	$193,864	–	–	$47,952	–	–

model chooses the capacity of wind and solar power to build in each MERRA grid cell and a profile of annual electricity generation results based on hourly wind speeds and solar irradiation. The resulting renewable energy output varies over each hour according to the variability in wind and solar energy in each location and hour. It is important to note, however, that we do not model potential errors in forecasting wind and solar availability. In practice, an electricity system planner would face forecast errors when predicting wind and solar production and would schedule additional back-up capacity to be available when forecasts are incorrect. Because we do not require additional back-up reserves, we likely under-estimate the dispatchable, balancing generation required to complement these variable renewables.

2.4. Hydroelectric modelling

We do not allow investment in new hydropower capacity. Though Canada has additional hydropower potential, the costs of new projects are geography-specific and unknown to us. Existing hydropower plants are, however, an important part of hourly dispatch in our model.

We divide existing hydroelectricity into three types: run-of-river (30% of existing capacity), day-storage (35% of capacity), and month-storage (35% of capacity).[8] These three technologies differ in their ability to store water for future electricity generation: run-of-river facilities cannot store water; day storage can store water over the course of a day; month-storage can store water over the course of a month.

Hydroelectricity production varies seasonally in Canada. We use monthly historic hydroelectric production data from Statistics Canada (2016); CANSIM Table 127-0002) to estimate average hourly electricity production by province and month.[9] Run-of-river facilities are non-dispatchable and produce a constant hourly amount of electricity that varies by month according to historical output. Day-storage hydro can store water and optimally allocate production over the course of 24 h. Production at day-storage plants is constrained so that total electricity generated does not exceed the average hourly production multiplied by 24 h. Similarly, month-storage can shift production over the course of a month, ramping up electricity production in times of peak demand, and holding back water during times of low demand. Month-storage hydro facilities are constrained so that total production over the course of a month does not exceed the average hourly production multiplied by the number of hours in the month. All hydro facilities are also constrained to meet minimum flow requirements, and to ensure that production does not exceed installed capacity in any given hour.

2.5. Demand data

Hourly electricity demand data is sourced from provincial electricity utilities (Fig. 3a; see SI for sources). Electricity demand includes exports to the US from the electricity exporting provinces: British Columbia, Manitoba, Quebec, and New Brunswick (Fig. 3b). It also includes imports from the US to British Columbia. Canada's domestic demand for electricity peaks in the winter (Fig. 3a), freeing up capacity to export electricity to the US in the summer months (Fig. 3b).

We model Canadian electricity demand in 2025 by scaling electricity profiles for each province to match the 2025 electricity demand forecast presented in the General Electric study (GE, 2016, Section 4, p. 29). Scaling factors are a weighted average of forecast growth in annual energy (GWh) and forecast growth in peak demand (MW), each weighted equally. We assume zero growth of exports to the US. This is a conservative assumption based on the US Energy Information Administration Energy Information Administration EIA's (2016) projection that electricity purchases from Canada will decline in the coming years.

We lack a detailed behavioural model of electricity consumption behaviour by electricity customers. For this reason, we do not model the potential for energy conservation actions that could lower electricity demand or demand response programs that could shift the timing of electricity demand. Instead, we focus on supply options for meeting a fixed level of electricity demand and do not allow demand to respond to electricity price.

2.6. Generation technologies and cost data

We model the potential for investment in the following generation technologies: coal-fired power plants, combined cycle natural gas-fired power plants, simple-cycle peaking natural gas-fired power plants, nuclear power plants, onshore wind power installations, and utility-scale solar power installations. Costs, fuel efficiency, and minimum and maximum annual capacity factors are drawn from Lazard (2016) and Energy Information Administration (EIA) (2017a) and summarized in Table 1.[10] Capital costs are amortized over 20 years for wind, solar, and natural gas combined cycle and peaking plants, and 25 years for all other generation technologies, storage facilities, and transmission lines.[11]

We include existing power plants in our model and account for

[8] While we do not observe the proportion of hydro storage facilities by type directly, we believe our storage assumptions are reasonable and in fact likely underestimate storage potential, especially the potential to store potential energy in reservoirs across seasons. In British Columbia, BC Hydro (2016) reports that the utility has averaged 12,400 GWh of stored potential electricity in its system over the past ten years and had 17,800 GWh of system storage at the end of their 2015 fiscal year. Total hydroelectricity production in B.C. in 2014 was 57,572 GWh, meaning average system storage was equal to 21.5% of the annual total and the 2015 level was equal to 30.9% of total production (BC Hydro, 2016; Statistics Canada, 2016: CANSIM 127-0007). Hydro Quebec finished 2015 with 126,900 GWh of system storage, up from 103,700 GWh at the end of 2014 (Hydro Quebec, 2016). Total Hydro Quebec sales were 200,847 GWh in 2014 and 201,127 GWh in 2015, meaning system storage at the end of 2015 was equal to 63% of total sales (Hydro Quebec, 2016). These numbers indicate that both provinces have a large storage capacity and that intra-day and intra-month storage is substantial.

[9] The majority of our scenarios rely on historic electricity production data from 2014, but in our sensitivity analysis we also test the impact of low precipitation years on optimal system investment using data from 2010.

[10] For example, Lazard (2016) lists the range of capacity factors for natural gas combined cycle plants as lying between 40% and 70%. We take the upper level bound as our maximum capacity factor for natural gas combined cycle plants. Lazard (2016) lists simple cycle peaking plants as having a 10% capacity factor, but the EIA (2017a) lists "conventional combustion turbines" as having a 30% capacity factor. We use the median value of 20% as the maximum capacity factor value for our peaking plant technology.

[11] We assume 20% debt-financing at 8% interest, and 80% equity financing at 12% interest.

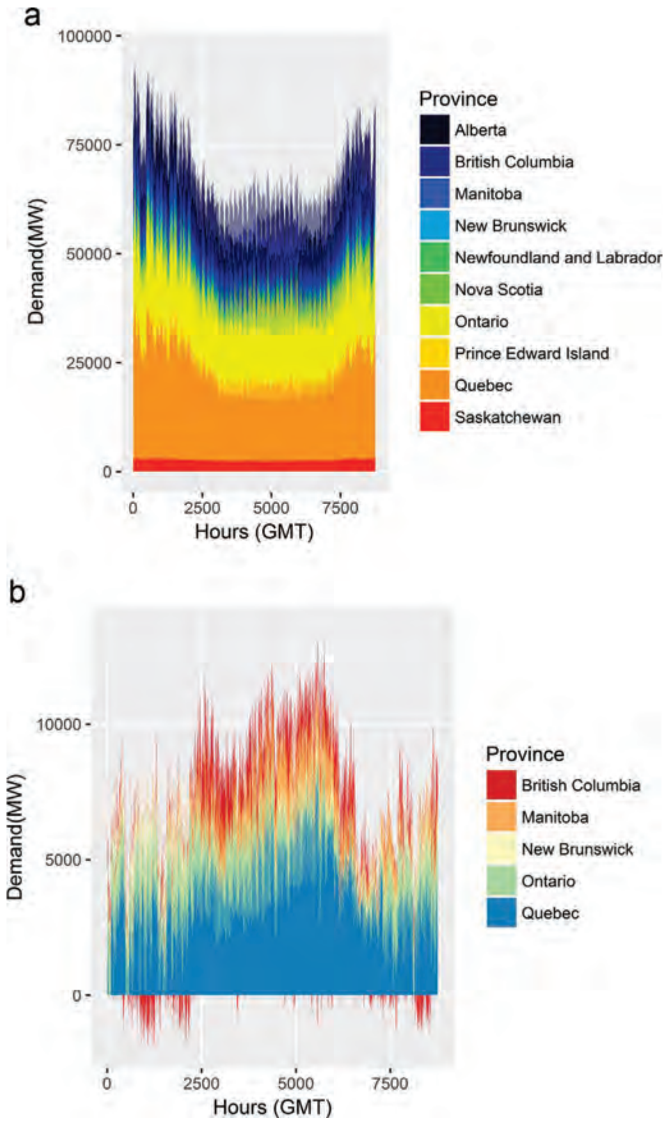

Fig. 3. a Canadian domestic electricity demand. b Electricity trade with the United States.

planned retirements expected by 2025 and the completion of three hydroelectric projects currently under construction in Canada (the resulting 2025 provincial capacity figures are presented in Fig. 2). We allow extant installations of diesel generators and waste power plants to be dispatched to meet hourly demand, but do not allow new investment in these technologies. For thermal generation technologies, we include fuel costs and model the GHG content of fuels (Table 2).

2.7. Storage cost data

New pumped-hydro facilities can be built to store potential energy and respond to variations in demand and variable renewable output. Cost and operating characteristics of pumped-hydro facilities are taken from Trottier Energy Futures Project (TEFP) (2016) and included in Table 1. We assume that storage facilities can provide eight hours of electricity generation at the nameplate capacity of the facility. We assume that 25% of energy is lost from pumping water to fill the storage facility.

2.8. Transmission technologies and cost data

We divide Canada into balancing areas that largely coincide with provincial boundaries, except for Ontario, Quebec, and Newfoundland and Labrador, which are each divided into two north-south balancing areas. New high-voltage direct current (HVDC) electricity transmission can be built to connect balancing areas. We include existing transmission connections in our model with data drawn from Trottier Energy Futures Project (TEFP) (2016).

Table 2
Cost and GHG content of fuels (various sources, see SI).

Fuel	\$ per GJ	Tonnes CO_2e per GJ
Coal	1.80	0.090
Diesel	25.80	0.072
Natural Gas	4.91	0.051
Uranium	1.00	0.000

Cost data for new inter-balancing area transmission lines is taken from GE (2016) and is representative of a 345 kilovolt (kv) HVDC line with 1500 MW of transmission capacity (see Table 3). We assume a fixed transmission loss of 2% and a variable transmission loss of 0.003% per km for electricity transmitted between balancing areas. Inter-balancing area transmission losses and costs are calculated based on centroid-to-centroid distances between balancing areas.

We account for the cost of connecting new wind and solar installations to existing transmission lines. Transmission costs associated with new wind and solar installations are \$557/MW/km/year, reflecting the amortized capital cost of a single-circuit 230-kv HVDC line (Table 2; GE, 2016). Extant transmission line data is collected from DMTI Spatial (2016) and summarized in Fig. 4.

2.9. Calculating the correlation between net electricity demand and electricity supply

The variability of wind requires a dispatchable supply of balancing energy. This energy can be supplied by domestic electricity generation, imports from neighbouring jurisdictions, or energy storage facilities. We calculate the sample Pearson correlation coefficient between net electricity demand (x) and the electricity supplied by various supply options (y_s) to understand which are most important for balancing wind output,

$$r_s = \frac{\sum_{h=1}^{8760}(x_h - \bar{x})(y_{s,h} - \bar{y_s})}{\sqrt{\sum_{h=1}^{8760}(x_h - \bar{x})^2}\sqrt{\sum_{h=1}^{8760}(y_{s,h} - \bar{y_s})^2}}. \tag{3}$$

Net electricity demand (x) refers to the electricity load that remains after accounting for the variable production of renewables like wind and solar. It is equal to Canadian domestic demand, plus exports to the United States, minus wind energy generation (and minus solar energy generation when solar is present).

2.10. Scenarios

We use our model to evaluate optimal electricity system configurations under different policy assumptions. All scenarios are run assuming forecast demand growth and scheduled capacity retirements for the year 2025. Because our model is a static, single-year model, we do not model the transition to the year 2025. Rather, we model the optimal system in 2025 based on our policy drivers: carbon pricing and emission reduction targets.

The Canadian government has announced their intentions for a national carbon price signal equivalent to \$10/tonne in 2018, escalating to \$50/tonne carbon dioxide equivalent (CO_2e) by 2022 (Prime Minister of Canada, 2016). We model carbon prices increasing in increments of \$10/tonne CO_2e from \$0 to \$200 to understand the ability of carbon pricing to motivate the decarbonization of electricity in Canada. We model two variants of our carbon pricing scenarios; one variant in which new transmission capacity between provinces is allowed, and another variant in which no new inter-provincial transmission capacity is allowed (in this scenario intra-provincial transmission can still be built between the north and south balancing areas within Ontario, Quebec, and Newfoundland and Labrador).

We then evaluate the cost of achieving complete decarbonization by constraining GHG emissions to zero in the model. This complete decarbonization scenario is evaluated with and without new inter-

Table 3
Transmission cost assumptions (various sources, see SI).

Transmission technology	Capital cost ($Million CAD/km)	Annualized capital cost ($CAD/MW/km/yr)	Fixed O & M ($/MW/yr)
Double-circuit 345 kv HVDC	$2.4	$184	$10,860
Single-circuit 230 kv HVDC	$1.6	$557	–

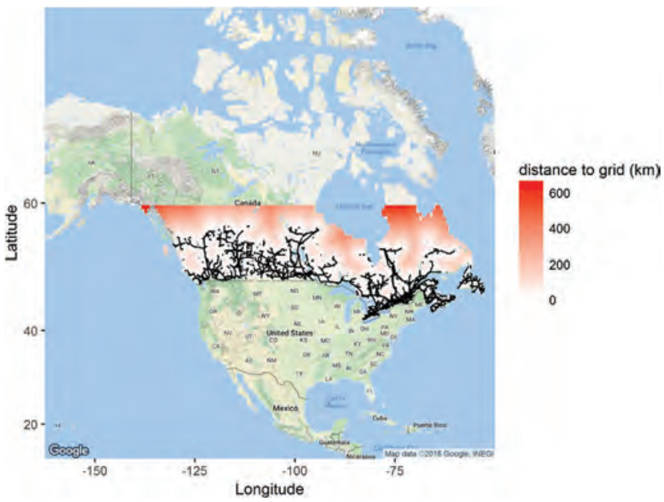

Fig. 4. Distance of MERRA grid cells to existing transmission grid (DMTI Spatial, 2016; author's calculations).[12]

provincial transmission.

Lastly, we conduct a sensitivity analysis where we vary natural gas prices, vary the capital cost of building new transmission lines, and restrict hydroelectric generation to represent a low-precipitation year.

2.11. Model limitations

Our modelling approach has the following limitations. First, we do not model plant investment in terms of discrete units. This means the optimization model selects investment levels in each technology and region on a continuous scale. For electricity technologies like wind turbines that can be built in increments of 1–3 Megawatts (MW) this is likely not a large concern. For technologies like nuclear power plants that must be built at minimum capacity values of 300–1000 MW, and transmission lines that are built at discrete capacities, this is a simplification of investment opportunities. The need to build units larger than selected by our optimization model would increase the cost of these technologies in our model.

Second, because we do not model discrete generations units, we do not use a unit commitment approach to dispatch available generation assets. In a unit commitment approach, dispatch occurs in two stages. In stage one, the model selects the level at which a dispatchable plant can operate in a future time-period. Wind and solar forecasts influence the required unit commitments. In stage two, units are dispatched at the required level given contemporaneous demand and renewable energy supply. Additional reserve generation capacity is required as a safeguard to ensure that supply can meet demand if demand exceeds expectations or renewable energy supply differs from the forecast. We do not require additional reserve capacity. We also assume that all installed capacity can ramp up and down concurrently (subject to ramp rate constraints). Both the lack of reserve requirements and the ability of plants to ramp concurrently mean our model likely underestimates the cost of responding to the variability of demand and renewable energy.

Third, we do not model intra-provincial electricity distribution in detail and our model does not consider power flow and frequency regulation (Dowds et al., 2015; Clack et al., 2017). Technologies like flywheels may be necessary to manage frequency regulation, especially in the face of higher integration of variable renewables. Our modelling results are best interpreted as accounting for the resource adequacy of wind and solar generation and the cost of providing back-up generation capacity that can respond to the variability of renewable generation (Dowds et al., 2015). Accounting for frequency regulation would likely increase total cost in our model.

Lastly, we assume that electricity demand is fixed at initial forecast levels. In effect, this means we assume perfectly inelastic electricity demand. While it is beyond the scope of our current analysis, allowing for price-responsive demand would have two impacts on our results. First, efforts to respond to higher prices would reduce the welfare of electricity consumers. We do not conduct a welfare analysis in this paper. Second, given a consistent carbon pricing signal throughout the economy, these efforts would lead to greater GHG emissions at any given carbon pricing level, increasing the effectiveness of carbon pricing.

Despite these limitations, we believe our results offer insights into the scale of electricity decarbonization costs, the role that renewables like wind and solar can play in decarbonizing electricity, the value of building new transmission and storage assets to balance the variability of renewables, and the effectiveness of carbon pricing in Canada.

3. Results

3.1. Cost

Carbon pricing motivates GHG emission reductions by increasing the cost of releasing emissions. Investments that reduce emissions for less than the carbon price will be undertaken, while more expensive actions will not. As such, the carbon price in our model serves as a measure of the marginal cost of abatement (Fig. 5).[13] Evaluating increments of $10/tonne CO_2e, we find that significant emissions reductions occur at a threshold carbon price of $80/tonne CO_2e when coal-fired plants in Alberta are retired (Fig. 5).[14] After this large emissions reduction, the marginal abatement stepwise cost curves begin to increase more steeply indicating diminishing mitigation opportunities.

The differences between the two stepwise curves after $80/tonne CO_2e indicates that new inter-provincial transmission allows for greater GHG emissions reductions at a lower cost (Fig. 5). GHG emissions in the reference scenarios are 110 Megatonnes (Mt) at a carbon price of $0/tonne CO_2e. At $200/tonne CO_2e, electricity sector emissions have been reduced by 86.7% (95.3 Mt CO_2e) when transmission is allowed (the black line in Fig. 4) and 82.7% (90.1 Mt of CO_2e) when no new transmission is allowed (the red line in Fig. 4). Allowing transmission achieves an additional 5% (5.2 Mt CO_2e) of emissions reduction at a marginal abatement cost of $200/tonne CO_2e.

As carbon prices are increased, investments in new low-carbon generation substitute for the continued operation of thermal power stations. More money is invested in capital (light blue bars in Fig. 6) and less is spent on fuel (black bars in Fig. 6).[15] Expenditures on carbon pricing increase until the price reaches $70/tonne CO_2e after which they decrease with the retirement of the Alberta coal-fired generation fleet. Carbon expenditures then remain roughly constant as emissions decline at a rate comparable to the increase of carbon prices. These carbon expenditures are a transfer of funds from the electricity utility to government and that

[12] Maps made using Google Map in R, open-source software described in Kahle and Wickham (2017).

[13] As noted, we do not model the price-elasticity of electricity demand. This means our marginal abatement costs represent upper-end cost estimates.

[14] The province of Alberta has introduced legislation to retire coal-fired electricity generation capacity by 2030 (Alberta Government, 2017). In our model this policy is equivalent to a $70–80/t$CO_2$ carbon price.

[15] Figure 6 is titled '*Incremental* Electricity Expenditure by Cost Category' because the figures do not display the complete costs of the Canadian electricity system. We do not account for payments on existing debt or administrative costs above operations and maintenance costs. The costs in Fig. 6a. and b. are limited to incremental capital costs for new generation, storage and transmission assets, and operational costs for all generation, storage and transmission assets.

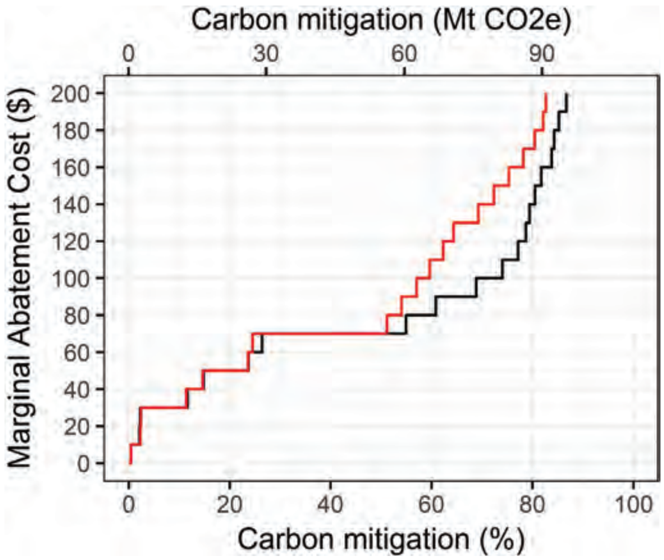

Fig. 5. Marginal abatement stepwise cost curve (year = 2025).

revenue can be recycled in ways that compensate the electricity utility or electricity customers, offsetting competitiveness impacts and limiting welfare impacts. For that reason, we do not include carbon costs in calculating the impact of emissions reductions on electricity costs below.[16]

Achieving emissions reductions will increase Canadian electricity costs (Figs. 6 and 7). Reducing emissions by 86.7% (95.3 Mt) in the new transmission scenario would result in an additional annual cost of $7.7 billion (CAD 2015) relative to the reference scenario.[17] Averaged across all electricity production, this would increase electricity costs by $12.3/MWh. When transmission is not allowed, reducing emissions by 82% (90.1 Mt) would cost $8 billion (CAD 2015) and would add an average $12.8/MWh to the cost of electricity. In 2015, electricity rates for residential customers in Canada ranged from $82 to $178/MWh (Natural Resources Canada, 2016). If averaged across all customers, the emissions reductions would generate a 7–15% price increase for these customers. Relative impacts on industry would be greater. Industrial electricity rates in Canada range from $44 to $115/MWh (Natural Resources Canada, 2016). Average industrial rates could rise by 10–28%.

As Fig. 5 indicated, a carbon price of $200/tonne CO_2e is not enough to motivate a complete decarbonization of the Canadian electricity sector in our model. Even with carbon prices of $450/tonne CO_2e, some GHG emissions remain in our optimized scenarios. To understand the cost of completely decarbonizing Canadian electricity we run scenarios where GHG emissions are constrained to equal zero. These scenarios result in an additional annual cost of $11.8 billion (CAD 2015) relative to the reference scenario when transmission is allowed, and $16 billion when transmission is not allowed. These costs in turn translate into average electricity cost increases of $18.9/MWh with new transmission and $26.4/MWh when new inter-provincial transmission is not allowed (Fig. 7). In these scenarios, the benefits of allowing transmission are clear. New inter-provincial transmission reduces the cost of completely decarbonizing the Canadian electricity system by $4.2 billion/year in our modelled scenarios; 26% below the costs of decarbonization without new inter-provincial transmission.

3.2. Generation mix

The optimal composition of Canada's generation mix shifts as carbon prices increase. Investments in wind power offer a low cost means of reducing emissions and are increasingly attractive at higher

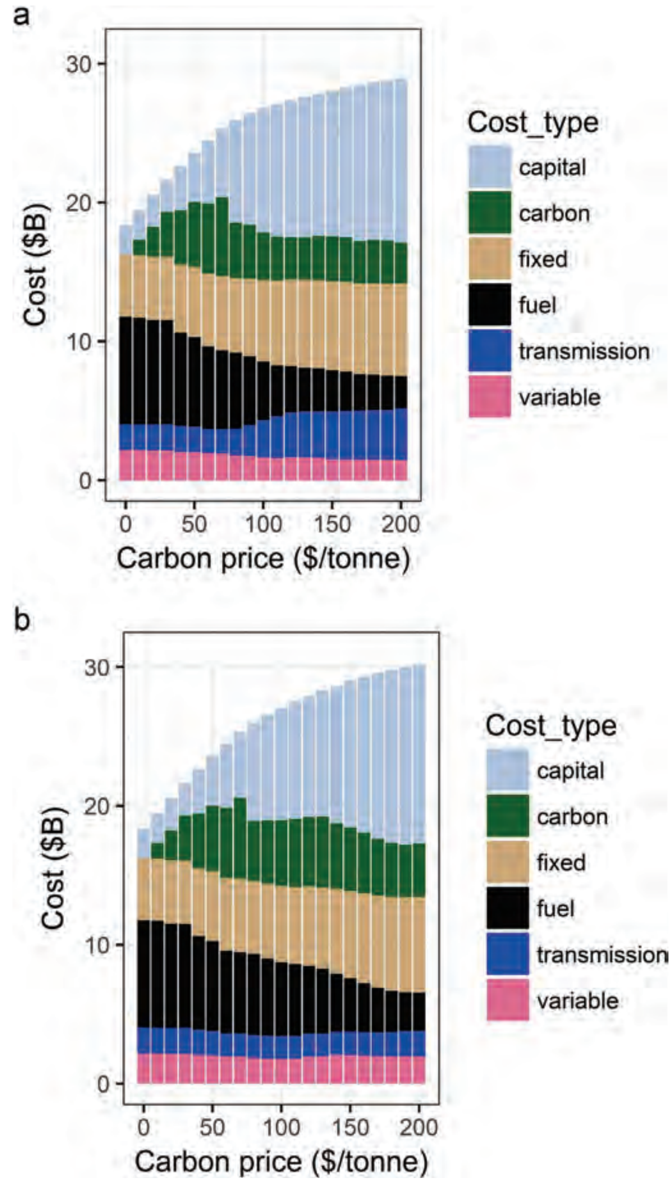

Fig. 6. Incremental electricity expenditure by cost category. a. New transmission allowed. b. No new transmission.

carbon prices (Fig. 8). At $200/tonne CO_2e, wind composes nearly 30% of the optimal generation mix. In the 100% decarbonization scenarios, wind represents 35% of generation when new transmission is allowed, and 33% when it is not allowed (Fig. 8c). These levels of wind penetration are comparable to the 35% of generation that GE (2016) found to be technically possible.

As mentioned above, it is optimal to retire coal plants in Alberta once carbon prices reach $80/tonne CO_2e. Combined cycle natural gas plants become a smaller portion of the optimal generation mix as the carbon price increases, except for a spike at $80/tonne CO_2e when they substitute for retired coal plants. Interestingly, natural gas combined cycle plants remain part of the optimal mix even at carbon prices of $200/tonne CO_2e. Though the levelized cost of electricity generated from a combined cycle natural gas plant exceeds that of wind power at carbon prices of only $12/tonne CO_2e, there is significant value to the dispatchable nature of natural gas plants that is not captured by measures of levelized cost.

Due to their high cost relative to wind power and natural gas plants, utility-scale solar facilities and new nuclear facilities are not part of the optimal mix at carbon prices of $200/tonne CO_2e. They are also not

[16] Note that the Canadian federal government has committed to provinces that all carbon revenue stays within the jurisdiction in which it was raised.

[17] The impact to average electricity costs excludes carbon pricing costs.

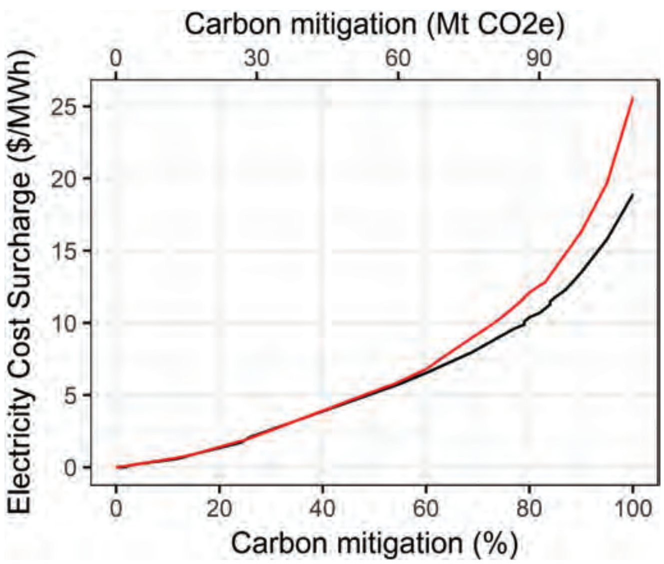

Fig. 7. Electricity cost impacts (year = 2025).

part of the optimal 100% decarbonization mix when transmission is allowed. Only when new transmission is not allowed and complete decarbonization of the electricity system is modelled, are new nuclear facilities part of the optimal mix. In that instance, they are built in British Columbia (1600 MW), New Brunswick (900 MW), and Nova Scotia (910 MW). Similarly, a small investment of 100 MW of solar in New Brunswick is optimal in the 100% decarbonization scenario when new transmission is not allowed. These results indicate that further cost improvements are necessary if either nuclear or solar are to offer a cost-effective means of reducing GHG emissions in Canada.

3.3. Geographic dispersion of wind facilities

The model finds that new wind facilities are optimally located in southern Alberta, Saskatchewan and Manitoba (Fig. 9a and b), southern Ontario (Fig. 9c and d) and locations along the east coast (Fig. 9e and f). The availability of new inter-provincial transmission lines changes the geographic dispersion of wind facilities. When new transmission is allowed, it is optimal to overbuild wind power capacity in Saskatchewan and export electricity to Alberta (Fig. 9a).[18] Without new transmission, the model locates additional wind capacity in Alberta (Fig. 9b). This finding contrasts with the GE (2016) study which concluded "there is no significant incentive to transport wind energy from slightly better wind locations over long distances (likely requiring new transmission facilities) when wind resources of almost equal quality are located closer to the provincial load centers where the energy would be used" (p. 18 of Section 1). Unlike the GE (2016) approach, we co-optimize the construction of generation and transmission assets. Using this approach, it appears there may be benefits to building wind power in the best sites and exporting electricity to neighbouring markets.[19]

[18] In the $200/tonne CO2e scenario, it is optimal to build 27.6 GW of wind capacity Saskatchewan when transmission is allowed and 6 GW when transmission is not allowed. Conversely, it is optimal to build 12.6 GW of wind capacity in Alberta when new transmission is allowed and 38.4 GW when no new transmission is possible. These levels of wind penetration are technically possible, but may not be socially acceptable (e.g. Höltinger et al., 2016; Jäger, 2016). We assume that wind power spacing requires 1 km^2 per 2 MW of wind capacity. In the 200/tonne CO_2e scenario, wind power would impact 13,794 km^2 of land in Saskatchewan. Much of southern Saskatchewan consists of cropland and pasture. More work is required to understand the degree to which wind turbines and agriculture are complementary, and the social acceptability of building wind power in rural communities.

[19] Note that the GE (2016) study also constrains wind to a maximum penetration of 50% of electricity generation in any one province. We do not constrain the penetration of wind in this manner.

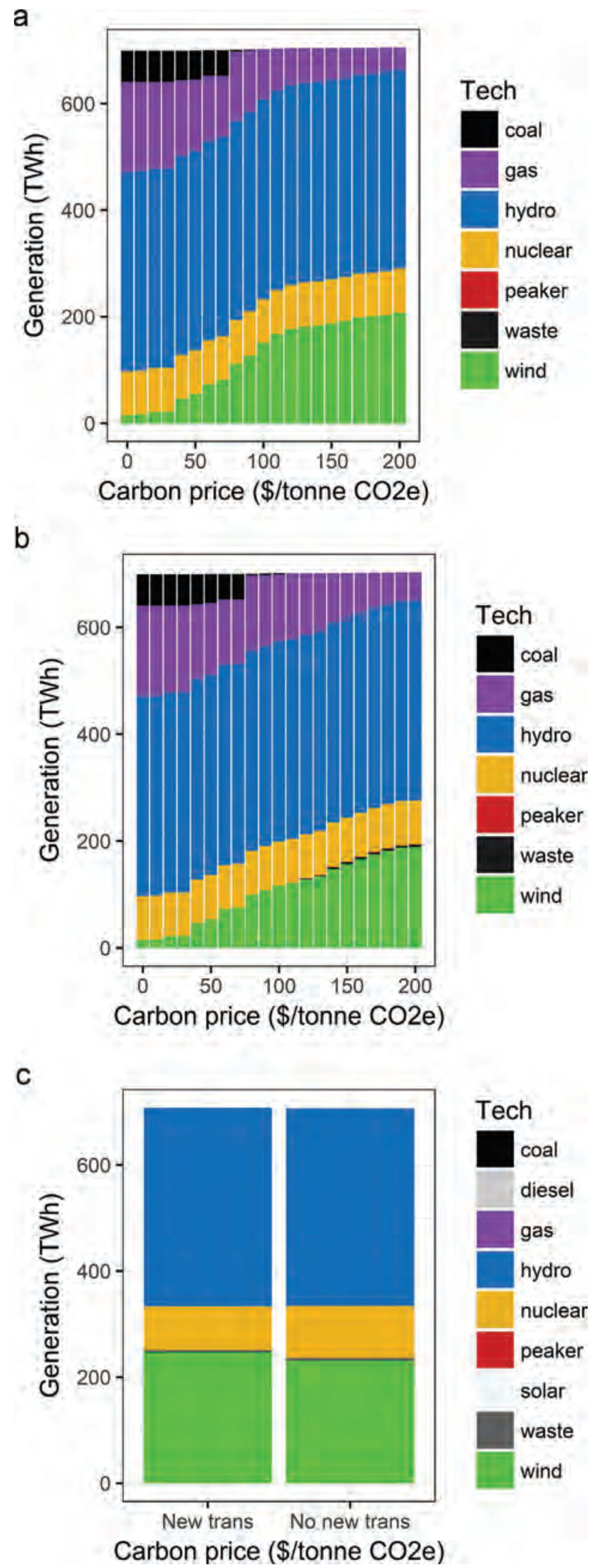

Fig. 8. Annual Canadian electricity generation by carbon price scenario. a. New transmission allowed b. No new transmission. c. Zero emissions.

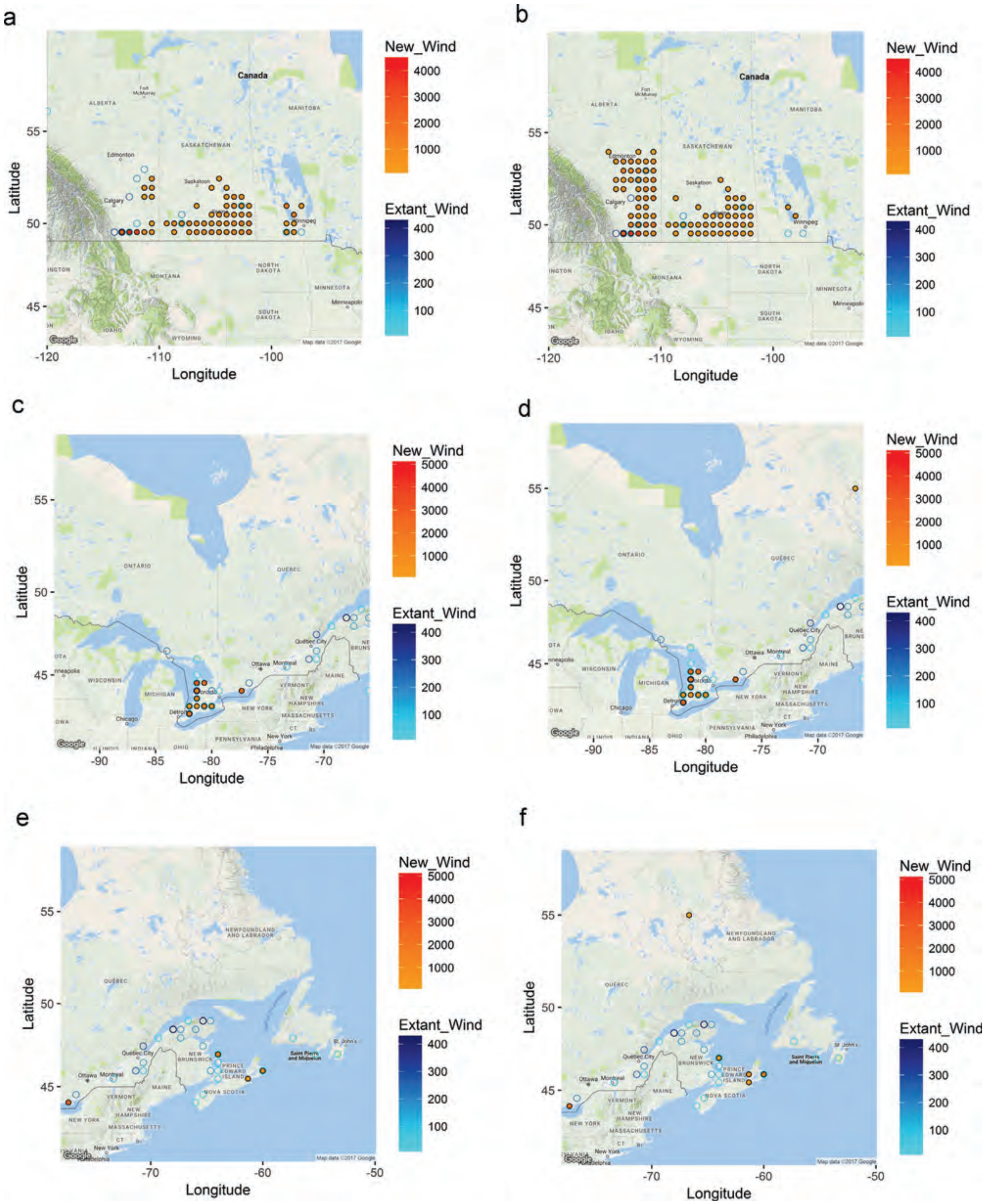

Fig. 9. Optimal wind power locations at \$200/tonne CO_2e. a. New transmission allowed. b. No new transmission. c. New transmission allowed. d. No new transmission. e. New transmission allowed. f. No new transmission.[20]

[20] Maps made using Google Map in R, open-source software described in Kahle and Wickham (2017).

3.4. Transmission

When allowed in our model, it is optimal to build new inter-provincial transmission in three main places.[21] First, it is optimal to build transmission links between hydro-producing Labrador and neighbouring power markets on the east coast of Canada (Fig. 10 and Table 4). This optimized east coast transmission network shows the desirability of the 'Maritime Link' transmission project currently under construction to connect Labrador's hydroelectric assets to the neighbouring island province of Nova Scotia via the island of Newfoundland (Emera, 2017). Our results also suggest a greater role for wind energy exports from Prince Edward Island. Second, it is optimal to build between northern Ontario and southern Quebec. Interestingly, transmission between Quebec and southern Ontario is not selected by the model. This may be due to our assumption of costless continuation of Ontario's nuclear fleet. Ontario's nuclear plants must be refurbished in the coming years. Further analysis is required to understand whether imports of hydroelectric energy from Quebec would offer a more cost-effective option for Ontario than nuclear refurbishment. Lastly, it is optimal to enhance transmission connections between the four western provinces. This "western interconnect" project has been discussed in Canadian policy circles in the past (Christensen and McLeod, 2016; Canadian Association of Engineering CAE, 2012). Our results suggest that a transmission line stretching from Manitoba to British Columbia has merit at \$200/tonne CO_2e (Fig. 10a). An extension of the "western interconnect" to north and south Ontario is optimal in our zero emissions scenario (Fig. 10b).

Our modelling shows that new transmission connections obviate the need to build energy storage facilities. When new inter-provincial transmission is allowed, storage is not selected at carbon prices of \$10–200/tonne CO_2e, and only a 28 MW storage unit in Saskatchewan is part of the optimal mix in the zero emissions scenario. When new inter-provincial transmission is not possible, it is optimal to build storage capacity in Alberta at carbon prices of \$160–200/tonne CO_2e, and 6475 MW of storage across Canada in the zero emissions scenario. Most of the storage selected in the zero emissions scenario is located in Alberta (5177 MW), with the remaining located in Saskatchewan (682 MW), Nova Scotia (482 MW), Prince Edward Island (106 MW), and New Brunswick (28 MW). Without enhanced transmission links to neighbouring provinces, storage is required to balance the variability of wind (see below).

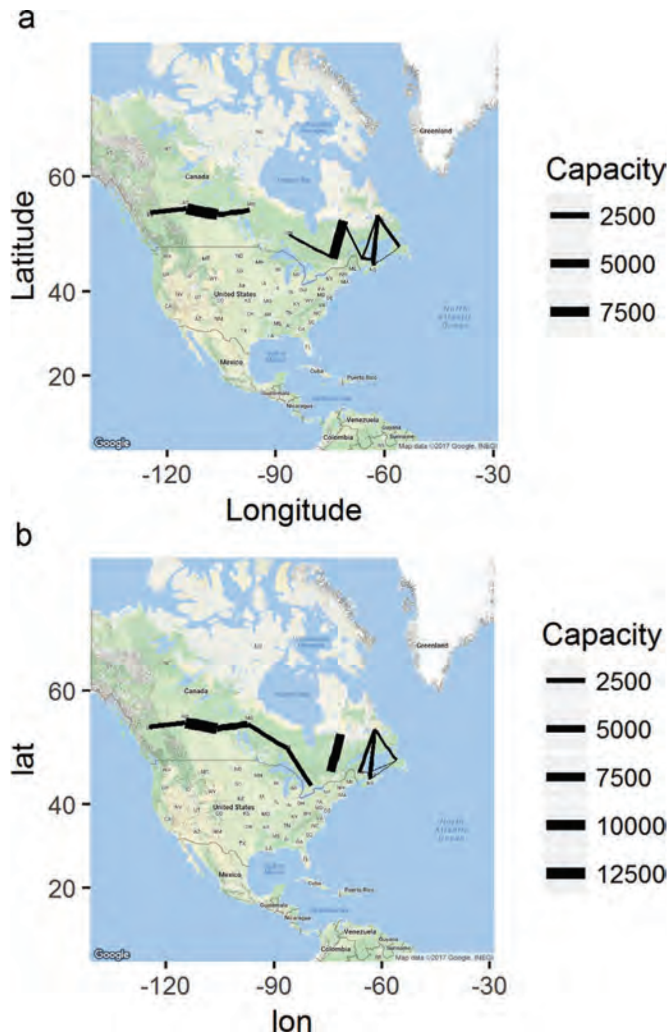

Fig. 10. Optimal transmission connections at \$200/tonne CO_2e. a. \$200/tonne CO_2e. b. Zero emissions.

Table 4
Inter-provincial HVDC transmission connections built at \$200/tonne CO_2e.

Exporting province	Importing province	MW
Alberta	British Columbia	1700
Saskatchewan	Alberta	9552
Manitoba	Saskatchewan	1858
Ontario (north)	Quebec (south)	459
Quebec (north)	Quebec (south)	7167
Quebec (north)	New Brunswick	356
Newfoundland and Labrador (south)	Nova Scotia	48
Newfoundland and Labrador (north)	New Brunswick	340
Newfoundland and Labrador (north)	Newfoundland and Labrador (south)	759
Newfoundland and Labrador (north)	Nova Scotia	954
Newfoundland and Labrador (north)	Prince Edward Island	440
Prince Edward Island	New Brunswick	437
Prince Edward Island	Nova Scotia	549

3.5. Balancing the variability of wind

The sample Pearson correlation coefficient between net electricity demand and the electricity supplied by various supply options identifies which supply options balance supply and demand in the face of variable wind output. Fig. 11a and b display the correlation between net demand and six supply options at the national scale for our carbon pricing scenarios. We find that hydropower facilities provide the dominant method of balancing the variability net demand across all carbon pricing scenarios. Second to hydro is trade, which plays an increasing role in balancing net demand when new transmission is allowed. Natural gas facilities also correlate positively with net demand, but their importance declines as carbon prices increase and gas plants are retired and used less frequently. The correlation between net demand and nuclear power output declines in higher wind integration scenarios. Nuclear power plants are constrained by slow ramp rates which make them less able to respond to the variability of net demand. Energy storage plays a balancing role in the \$160–200/tonne CO_2e scenarios when new transmission is not allowed (Fig. 11b). These results highlight the potential for Canada's hydroelectric assets to enable a much higher penetration of wind energy. They also highlight the value of transmission, and the limited role required of energy storage, to balance the variability of wind.

3.5.1. Sensitivity analysis – natural gas

The scenarios above assume a natural gas price of \$4.91/GJ. Annual

[21] In all our scenarios, intra-provincial transmission is built between northern Quebec and southern Quebec to enhance electricity exports from the hydropower plants in the north to southern markets. New *intra*-provincial transmission is permitted in the model even when no new *inter*-provincial transmission is not.

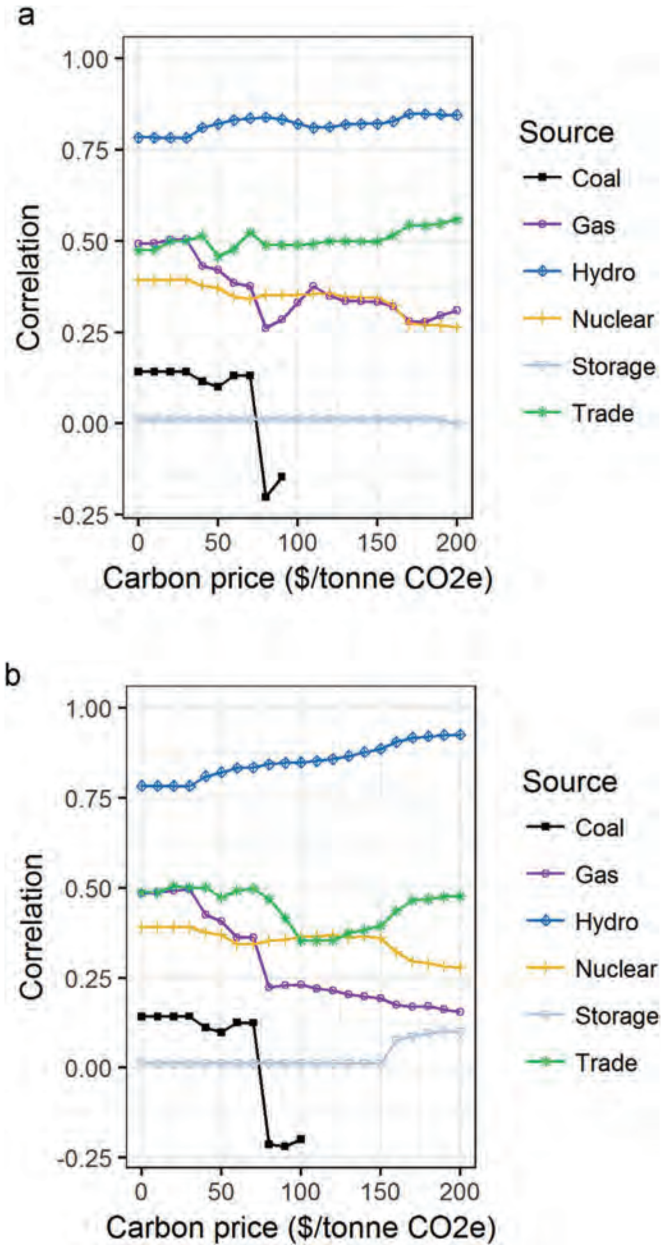

Fig. 11. Correlation between net demand and supply options. a. New transmission allowed. b. No new transmission.

average natural gas prices have varied between $2.52 and $8.69 USD/GJ within the past ten years (Energy Information Administration (EIA) 2017b). Fig. 12a, b, and c summarize how the optimal generation mix (12a), resulting GHG emissions (12b), and annual costs (12c) vary in response to natural gas prices ranging from $2 to $8.50 CAD/GJ. In these scenarios, we assume a carbon price of $80/tonne CO_2e. This is the carbon price that would be achieved in 2025 if the Canadian government escalates the carbon price by $10/year beginning in 2018.

Fig. 12b shows that GHG emissions are highest in the low natural gas price scenarios where natural gas generation crowds out investments in wind energy (Fig. 12a). GHG emissions remain around 50 Mt in scenarios with natural gas prices of $5/GJ to $7.5/GJ. Emissions are again higher at prices of $8/GJ and $8.5/GJ. In these high-priced natural gas scenarios, the fuel cost penalty for natural gas outweighs the carbon penalty on coal, and coal-fired generation crowds out natural gas generation. Annual costs uniformly increase as natural gas prices increase (Fig. 12c). Most of the increasing cost comes from increasing investments into new wind power capacity. Optimal capital investments in wind increase costs by $1 billion/year at a natural gas price of $2/GJ and $8 billion/year at a natural gas price of $8.50/GJ.

3.5.2. Sensitivity analysis – transmission costs

The scenarios presented above assume an amortized capital cost of $184/MW/km/year for HVDC transmission lines. To test the robustness of our results we vary transmission capital costs between $100 and $600/MW/km/year. In these scenarios we constrain greenhouse gas emissions to be zero, which represents full decarbonization of the electricity system. As Fig. 13 demonstrates, transmission and energy storage are clear substitutes in our model. As HVDC transmission capital costs rise, investments in transmission decline and investments in storage increase. Investments in wind also increase in the high-cost transmission scenarios. With less transmission capacity, wind must be built closer to load and at less optimal wind sites, requiring more wind to be built in aggregate. More wind is also necessary because there is an energy penalty for using storage.

Annual costs range from $28 billion/year when HVDC lines cost $100/MW/km/year scenario, to $36 billion/year when HVDC costs are $600/MW/km/year. Of interest, it is optimal to build new transmission lines throughout the country even at HVDC capital costs of $600/MW/km/year. For example, even in this high-cost scenario, our model recommends a 450 MW connection from Manitoba to Saskatchewan, a 1300 MW connection from Saskatchewan to Alberta, and a 2100 MW connection from Alberta to British Columbia.

3.5.3. Sensitivity analysis – low hydroelectric years

In the scenarios above we model the availability of hydroelectric generation based on 2014 data when total hydroelectric electricity generation in Canada was 375 Terrawatt-hours (TWh) (Statistics Canada, 2016, CANSIM Table 127-0002). During years with low precipitation, hydroelectric output can fall. To understand the impact of low hydroelectric availability on our optimal electricity mix, we ran carbon pricing scenarios with hydroelectric generation data from 2010, when hydroelectric output was only 347 TWh. With less hydroelectric generation, more investment must be made in new generation capacity and costs increase by 6.6–8.1%. The contribution of hydroelectricity drops from 53.5% of total generation to 49.6% of the total. In low carbon price scenarios, this supply gap is made up by combined cycle and peaking gas plants. When carbon pricing is introduced, investments in wind power increases to make up for the loss of hydroelectric generation, and wind generation expands from 29.5% to 34% of supply at a carbon price of $200/tonne CO_2e. A useful way to prepare for low-hydro years may be to overbuild wind capacity and seek opportunities for greater exports to the United States during wet years.

4. Conclusion and policy implications

The Government of Canada has set a 2030 goal of reducing GHG emissions to 30% below 2005 levels. Reductions in the electricity sector can contribute to meeting this target. We find that least-cost emissions reductions within Canada's electricity sector are achieved by expanding Canada's wind power capacity. Canada can use its strong wind resources to generate electricity, and can use existing hydropower assets and enhanced electricity trade between provinces to balance the variability of wind.[22]

A shift towards wind power can be motivated by carbon pricing. Building on carbon pricing efforts by British Columbia, Quebec, Ontario, and Alberta, the Canadian government announced a national carbon price that will begin at $10/tonne CO_2e in 2018 and rise to $50/

[22] Further analysis with improved wind data is desirable. We validated the MERRA wind data against recorded Environment Canada wind data and found that, on average, MERRA wind data overestimated wind speed by 17% and underestimated the variability of wind (see Supplementary Information). Lower wind speeds and higher variability would increase the cost of integrating wind energy onto the electricity system and could lead to lower penetration of wind in optimized scenarios. To support detailed modelling of the Canadian electricity system there is a need for greater investment in high-quality, hourly and sub-hourly wind speed data.

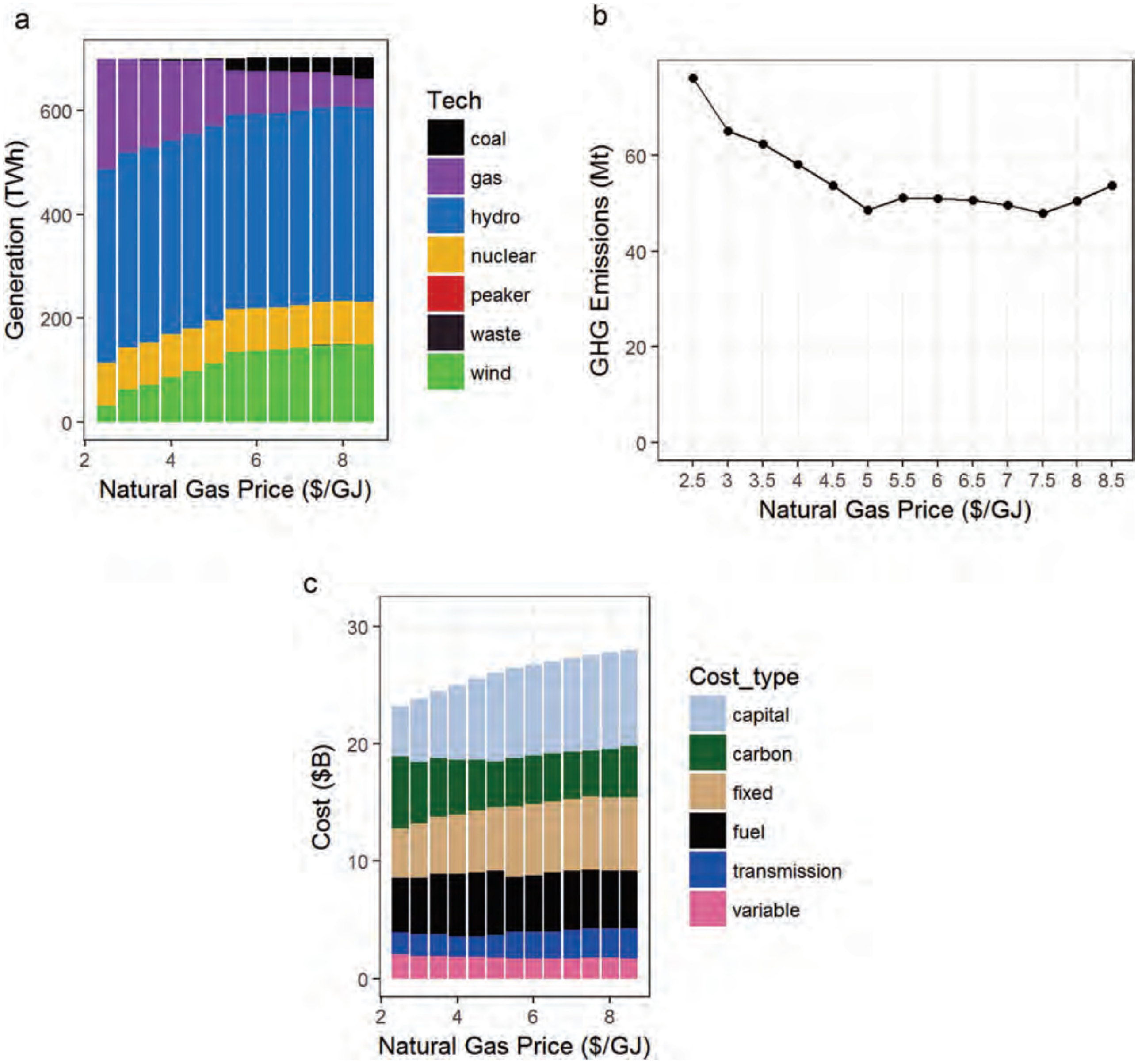

Fig. 12. Natural gas sensitivity analysis. a. Optimal generation mix. b. Greenhouse gas emissions. c. Annual costs.

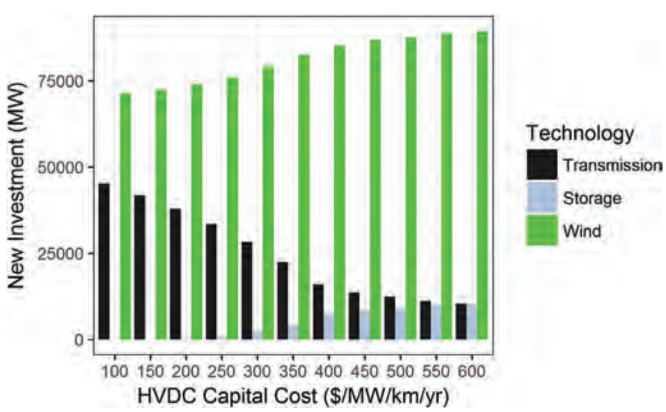

Fig. 13. Transmission cost sensitivity analysis.

tonne by 2022 (Prime Minister of Canada, 2016). We find that a $50/tonne CO_2e carbon price could decrease greenhouse gas emissions in the electricity sector by 20–21% below Canada's 2005 electricity sector emissions (Environment and Climate Change Canada, 2017).[23] If Canada is to significantly decarbonize the electricity sector by 2030, Canada's carbon price must continue to rise beyond 2022.

The Canadian government has introduced regulations that impact Canada's coal-fired power plants. In 2012, the Canadian government introduced regulations requiring coal-fired facilities to achieve a performance standard of 420 tonnes CO2e / Gigawatt-hour (GWh) when they reach the end of their 50-year useful life (CEPA (Canadian Environmental Protection Act), 2012). This standard can be achieved by retiring coal plants or equipping units with carbon capture and storage technology. In 2016, the Canadian government announced plans to tighten those regulations to ensure that all plants meet the performance standard by 2030 (Government of Canada, 2016b). The accelerated coal phase-out offers a substitute for higher carbon prices. Our modelling suggests that retiring coal and replacing it with lower-carbon generation sources like wind power and natural gas facilities has an implied marginal abatement cost of between $70–80/tonne CO_2e

[23] Note that reductions would be deeper had we modelled price-responsive electricity demand.

and reduces GHG emissions to 54–58% below 2005 levels. The coal phase-out increases total electricity system costs by $3.4–3.6 billion/year (CAD 2015), which, averaged across demand equals $5.4–5.8/MWh.

To achieve the reductions outlined in *Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy* (Government of Canada, 2016a), Canada must contemplate complete decarbonization of the electricity sector. In this instance, policies beyond carbon pricing are likely required. Beyond $80/tonne CO_2e, the marginal abatement stepwise cost curve increases steeply. Each $10/tonne increase of the carbon price motivates the retirement of additional natural gas capacity, but natural gas capacity is not fully retired in our model even at very high carbon pricing levels of $450/tonne CO_2e. This is because, despite a higher levelized cost, natural gas provides valuable balancing services. A natural gas phase-out would help lower electricity sector emissions to zero, but would require additional investment in low-carbon generation, new transmission lines, and, if new inter-provincial transmission is not possible or is cost-prohibitive, energy storage facilities. Achieving complete decarbonization by 2025 adds another $8.2–12.6 billion (CAD 2015) to annual costs in our modelled scenarios, increasing total annual costs by $11.8 billion over the reference scenario when it is possible to build new inter-provincial HVDC transmission connections, and by $16 billion (CAD 2015) if it is not possible to build new inter-provincial HVDC transmission links. This means that the availability of new transmission could reduce decarbonization costs by $4.2 billion (CAD 2015) or 26%. If HVDC capital costs exceed $184/MW/km/year, complete decarbonization is more expensive. At HVDC capital costs of $600/MW/km/year, total annual costs increase by $17.5 billion (CAD 2015), nearly doubling the $18.3 billion (CAD 2015) annual cost of the reference scenario. Even in these high HVDC cost scenarios, it remains optimal to build new transmission lines throughout Canada.

Our modelling demonstrates there is value to building new inter-provincial transmission lines. As the Canadian Academy of Engineering (Canadian Association of Engineering CAE) writes, "The main obstacle (to new inter-provincial transmission) remains the political will to commit to such an objective, and to craft a workable financial architecture which spreads both risk and return on investment among all stakeholders" (2016: 73). Canada's federal structure means that the Canadian government could play an important coordinating role. The moment for coordination may have arrived. The Canadian government has signalled its willingness to fund new inter-provincial transmission projects (Government of Canada, 2016b), and our research shows that these projects may help Canada to meet its GHG emission reduction goals at a lower cost to Canadians. To validate these findings, we suggest the need for additional modelling that would include detailed intra-province transmission and distribution networks, electricity demand and renewable energy supply detail at the sub-hourly level, and the exploration of integer programming and unit commitment approaches to electricity modelling.

Acknowledgements

The authors would like to acknowledge helpful comments from discussant Randall Wigle (Wilfred Laurier) and participants at the Canadian Resource and Environmental Economics (CREE) conference in Banff 2016, discussant Werner Antweiler (UBC) and participants at the Canadian Economics Association (CEA) conference in Antigonish 2017, discussant Valerie Karplus and participants at the Toulouse School of Economics Conference on The Economics of Energy and Climate Change 2017, and two anonymous reviewers. The authors would also like to thank Philippe Kabore (University of Ottawa) for his research assistance. The authors accept responsibility for any remaining errors and omissions contained within the article.

Funding Support

Dolter acknowledges the funding received from the Social Science and Humanities Research Council Postdoctoral Fellowships Program. Rivers acknowledges the funding received from the Social Science and Humanities Research Council Canada Research Chairs Program.

Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at http://dx.doi.org/10.1016/j.enpol.2017.10.040.

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ELECTRICITY AFFORDABILITY AND EQUITY IN CANADA'S ENERGY TRANSITION

Options for rate design and electricity system funding

Brett Dolter
University of Regina

Jennifer Winter
University of Calgary

Aligning Canada's electricity systems with net zero emissions will increase electricity use and has the potential to increase households' electricity expenditures. To inform policy discussion and actions for aligning electricity systems with net zero, we explore how net zero investments will affect electricity systems' costs and households' expenditures.

Our overarching research question is *how will increased electrification affect household costs by province and across the income distribution*? We find that while electricity use will increase, households' total electricity expenditures may not. These changes could exacerbate pre-existing equity issues: with a status quo approach to funding electricity system investments, the resulting system is likely to increase electricity expenditures for lower-income households relatively more than higher-income households. We explore two options for mitigating this regressivity in electricity system costs: rate-design changes and tax-system funding of system investment costs. Both approaches are tools that, in different ways, can help address regressivity and electricity affordability. Applying these tools independently or in combination provide multiple levers for policymakers to address equity and efficiency goals in the net zero transition.

This scoping paper is part of a series commissioned by the Canadian Climate Institute that explores key topics in aligning Canada's electricity systems with net zero, which culminated in the Institute report *The Big Switch*.

INTRODUCTION

Canada's commitments to reduce emissions, in line with global efforts to avert catastrophic climate change, require net zero emissions by mid-century. Achieving net zero emissions by 2050 requires changing how Canadian households and firms use energy; a large part of that change is increased electrification (Dion et al. 2021, 2022; Environment and Climate Change Canada 2022). Emissions from electricity are expected to decline by 77 per cent between 2019 and 2030, and electrification will account for 17 per cent of the expected emissions reductions between 2019 and 2030 (Environment and Climate Change Canada 2022). However, aligning electricity systems with net zero will require significant expansion of generation, transmission, and distribution infrastructure (Lee, Dion, and Guertin 2022). New investments in these fixed assets will in turn affect electricity bills. Absent policy interventions, costs of the expanded system will be borne by residential, commercial, and industrial consumers.

To inform federal and provincial policy options for aligning electricity systems with net zero, we explore how net zero investments will affect electricity system costs and costs for households. Our overarching research question is *how will increased electrification affect household costs, by province and across the income distribution*? There are three primary ways increased electrification will affect household costs. First, by changing electricity rates (the price households pay for electricity). Second, by changing electricity use. Third, by reducing expenditures on fossil fuels like gasoline, diesel, and natural gas. Electricity rates will change because of the changing composition of electricity generation (with different costs relative to the current mix) alongside increased system investments to support increased system load. Electricity use will increase due to electrification, with electricity becoming the default energy source for homes, vehicles, businesses, and industries. Correspondingly, expenditure on fossil fuels will fall as users switch to electricity in end uses. These changes may affect the affordability of electricity, though the overall costs of energy (household spending on electricity, natural gas, gasoline, heating oil, etc.) will decline (Dion et al. 2022). For lower-income households, who may not have the financial means to adjust their behaviour and energy sources, energy affordability is a key issue.

To explore the intertwined issues of electricity system change and electricity affordability, we focus on households' costs with four related research questions:

1. How much are households currently spending on electricity, and how do these costs differ across provinces and across the income distribution?
2. What will happen to households' electricity costs—both rates and total expenditure—on the path to net zero?
3. As electricity use and rates change, how will this affect Canadian households' electricity expenditure in different provinces and across the income distribution?
4. How would different rate structures and ways of funding electricity system investments change the incidence of system costs on households?

In answering our first research question, we use microdata—detailed household characteristics and expenditure data—from Statistics Canada's Social Policy Database and Model (SPSD/M).[1] Using these data, we describe current electricity expenditure patterns by province and income quintile. We then combine electricity expenditure with province-specific prices to impute household electricity use.

In answering our second research question, we use models of electricity system investments from three modelling teams— the Canada Energy Regulator (CER), ESMIA (Institut de l'énergie Trottier), and the Electric Power Research Institute (EPRI)—augmented with current utility debt costs to construct average costs of generation in 2030, 2040, and 2050. We translate these costs to a volumetric residential rate using a province-specific constant markup.[2] Using these estimated costs, we describe utility cost pressures and the volumetric and total costs for households in 2030, 2040, and 2050. We assume current electricity rate design in each province remains unchanged, and use scaling factors to increase households' volumetric and fixed charges relative to 2021.

In answering our third research question, we dive into how reference-case average household electricity expenditure, volumetric rates, fixed charges, and total household electricity costs differ across provinces and across the income distribution within each province.

[1] SPSD/M is "a non-confidential, statistically representative database of Canadian individuals in their family context, with enough information on each individual to compute taxes paid to and cash transfers received from government" (Statistics Canada 2022). We use SPSD/M version 29, which has a base year of 2017, the latest available data. The assumptions and calculations underlying the simulations were prepared by the authors and the responsibility for the use and interpretation of these data is entirely theirs.

[2] The markup is the difference between average household electricity costs ($/kWh) and modelled average generation cost ($/kWh) for the entire electricity system in 2020. The markup can result from a range of factors including return on equity, administrative costs, higher distribution costs for residential customers, and other costs for which we don't have modelling data.

DEFINITIONS

Household electricity expenditure: Total costs on an electricity bill, consisting of fixed charges and the volumetric rate (price) per kilowatt-hour (kWh) multiplied by use.

Volumetric rates: Electricity rates per kWh faced by households.

Fixed charges: Connection fees charged at a flat rate to all residential users, typically charged on a monthly or annual basis.

Electricity rates: Include monthly or annual fixed charges and the volumetric rates.

Average household electricity cost: The average cost of electricity per kWh for residential customers, constructed by dividing total household costs ($) by total household use (kWh). It combines fixed charges and volumetric rates.

Total household costs: Annual household electricity costs, including income tax increases in the scenarios where government directly funds part of net zero system investments through increased taxes.

Modelled average generation cost: The average electricity system cost. We calculate this by dividing all system costs, including amortized debt, by total modelled generation. This is measured in dollars per MWh or cents per kWh.

In answering our fourth research question, we compare different electricity rate structures and *system-funding* policies, as these are potential policy tools to mitigate equity concerns from increased system costs. Our baseline, or reference case, is that existing provincial rate structures continue. We examine three scenarios with different rate designs, and two scenarios with alternative system funding structures. These policy options are not mutually exclusive and are possible to use in combination, nor are they exhaustive of the potential policy options. They are, however, illustrative of how policy action could mitigate some of the negative equity consequences of net zero investments.

The rate-design scenarios explore different ways of levying transmission and distribution costs as a fixed charge, rather than (fully or partially) folded into volumetric rates. The scenarios are (1) a uniform fixed charge across all households; (2) a means-tested fixed charge (increasing with income) matching the progressivity of the GST's burden across the income distribution; and (3) a means-tested fixed charge matching the progressivity of federal personal income taxes. In the absence of a specific distributional goal, the three scenarios illustrate the equity considerations implicit in existing rate design versus alternatives.

We also explore two scenarios with 50 per cent government funding of the net zero investments. This reflects the notion that decarbonization through electrification and reducing emissions in the electricity sector is a policy objective rather than a system (or regulator's) objective. Moreover, governments may be better suited than private companies to absorb these costs, with the advantage of lower borrowing costs and a tax base larger than a rate base. We abstract from how government chooses to implement 50 per cent funding of the electricity system and focus on the net costs to households with 50 per cent public funding (net household costs are inclusive of their expenditure on electricity and their increased tax expenditure that results from the greater use of public funding). The two scenarios are (1) federal personal income tax increases; and (2) provincial personal income tax increases. Our choice of 50 per cent government funding of net zero system investments is arbitrary and meant to illustrate the equity and inter-provincial trade-offs of this mechanism of funding system investments.

We find that while electricity use will increase, households' total electricity expenditures may not. Major investments are necessary to align electricity systems to net zero, but the scale and scope of these investments differ by province, which has an important effect on electricity rates, and will depend on the future costs of generation, storage, and transmission technologies. Thermal provinces that currently rely on coal, natural gas, or oil for significant electricity generation—Alberta, Saskatchewan, Ontario, and the Atlantic provinces—are at greater risk of increasing volumetric rates (cents per kWh) and higher electricity expenditures. Even hydro provinces could see expenditures increase for lower-income households between 2020 and 2050. Rate design and funding approaches will be crucial in determining the distributional consequences of this change.

However, all of this will occur in the context of a changing energy system. Increased household electricity use will correspond with decreased use of gasoline, natural gas, and other fossil fuels. While spending on electricity will likely increase, total energy spending will decline (Dion et al. 2022).

Figure 1

Energy spending and electricity spending shares, 2020 to 2050

Source: Dion et al. (2022).

There are already existing policies in place—both general and targeted—to address energy affordability in Canada. Direct and targeted policies include means-tested bill rebates (for example, the Ontario Electricity Support Program (Ontario Energy Board n.d.-b)) and emergency financial assistance programs (for example, Ontario's Low-income Energy Assistance Program (Ontario Energy Board n.d.-a) or Alberta's Emergency Needs Allowance (Government of Alberta n.d.)). Other policy actions are temporary and targeted, such as Alberta's fuel tax holiday (Government of Alberta 2022). Indirect and targeted policies to address affordability include subsidies for energy-efficient investments (for example, the CleanBC Better Homes and Home Renovation Rebate Programs (CleanBC n.d.) or Manitoba's means-tested Energy Efficiency Assistance Program (Efficiency Manitoba n.d.)), and property-assessed clean energy programs (for example, Edmonton's Clean Energy Improvement Program (City of Edmonton n.d.) or Halifax's Solar City program (Halifax Regional Municipality n.d.)). The means-tested (for example, British Columbia's Climate Action Tax Credit) or lump-sum carbon tax rebates (for example, the federal Climate Action Incentive) can also be included as a general affordability policy action. However, the issue of energy poverty and energy affordability is understudied in Canada and there is no official definition of energy poverty (Shaffer and Winter 2020; Das et al. 2022; Das, Martiskainen, and Li 2022). We shed light on current and future electricity affordability and demonstrate how policy intervention can improve equity in Canada's net zero transition and address longer-term electricity affordability.

We next discuss current electricity expenditure by households, and the relative burden and affordability of electricity. We then briefly describe our methods and results for calculating residential electricity use change, modelled changes to residential rates, and modelled changes to household costs. We discuss the distributional consequences of expected household cost changes under different rate-design scenarios and the effect of different funding scenarios on electricity expenditure, variable rates, and fixed costs. We conclude by summarising our key results.

CURRENT ELECTRICITY USE AND AFFORDABILITY IN CANADA

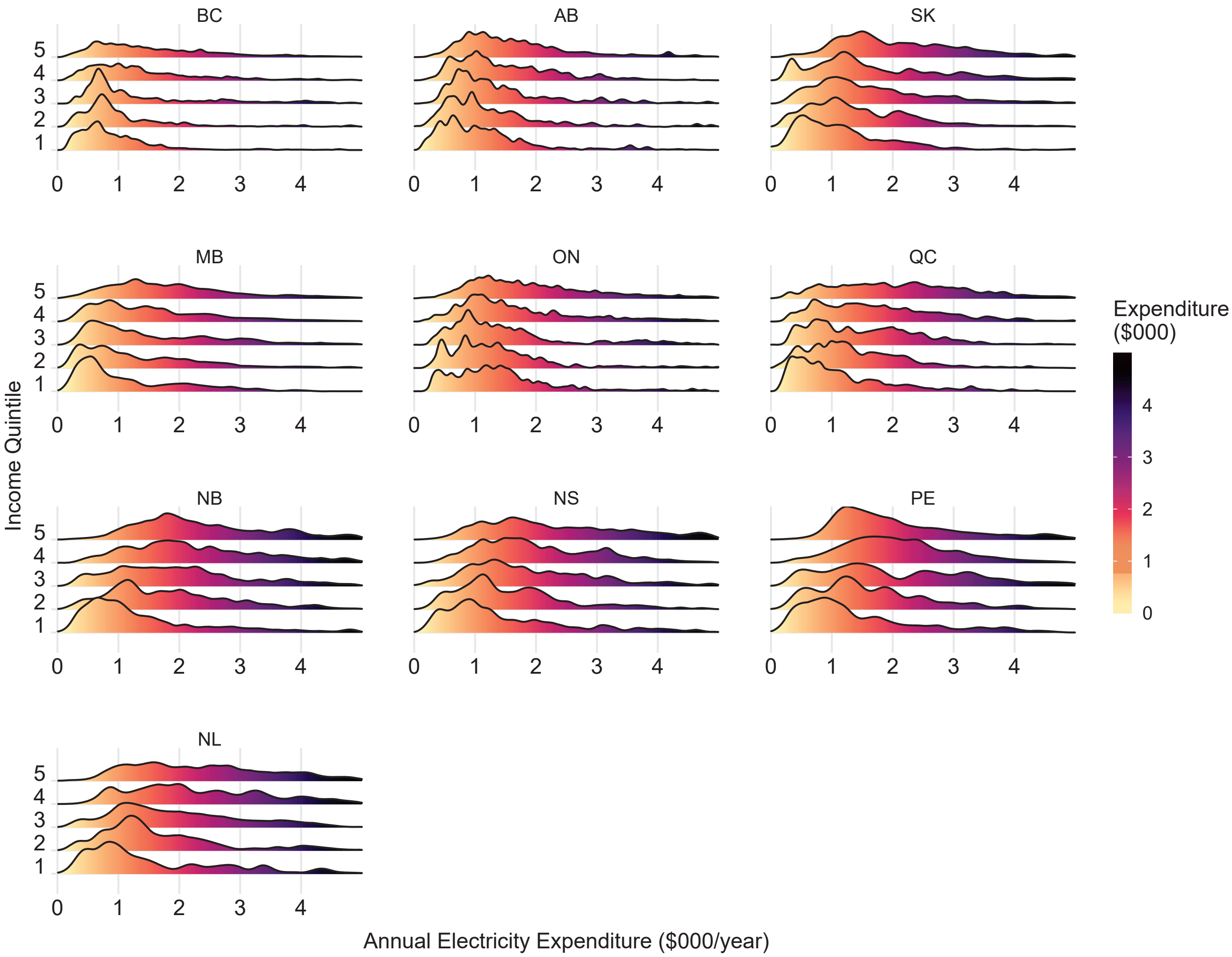
In this section, we present current household electricity expenditure using 2017 microdata from Statistics Canada's Social Policy Simulation Database and Model (SPSD/M). The database portion of SPSD/M is "a non-confidential, statistically representative database of Canadian individuals in their family context" (Statistics Canada 2018). The SPSD combines data from multiple sources and is the only integrated database with data on income, taxes, expenditure, employment information, and socio-economic characteristics.[3] These data form the basis of our analysis of how net zero investments affect households' electricity costs, the distributional consequences of a changing electricity system, and how policy choices on cost-sharing of these investments affect households. SPSD/M is a rich database of representative households in each province and ideal for our specific interests.

Figure 2 shows the distribution of households' annual electricity expenditure by province and income quintiles within each province, excluding households with no expenditure on electricity.[4] In most provinces, the majority of households in the first (lowest-income) quintile spend between $1 and $1,000 on electricity annually (as shown in the highest peak between zero and one). However, in the fifth (highest-income) quintile, annual electricity expenditures vary more as we see a relatively flat line, a nearly equal number of households spending between $500 and $3,000 on electricity expenditures annually. Importantly, this figure presents total expenditure, masking the relative roles of use, fixed costs, and volumetric rates in expenditure. We return to this issue in our analysis below.

[3] The data are synthetic, in that they are constructed from multiple sources (the Canadian Income Survey, personal income tax returns, employment insurance claimant history data, and the Survey of Household Spending), and there is no link across these datasets. However, the database is specifically constructed to be representative based on the underlying data.
[4] These are households that likely have electricity included in their housing costs, i.e., renters who do not pay utilities.

Figure 2

2017 Annual electricity expenditure by province and income quintile (thousand 2022 dollars)



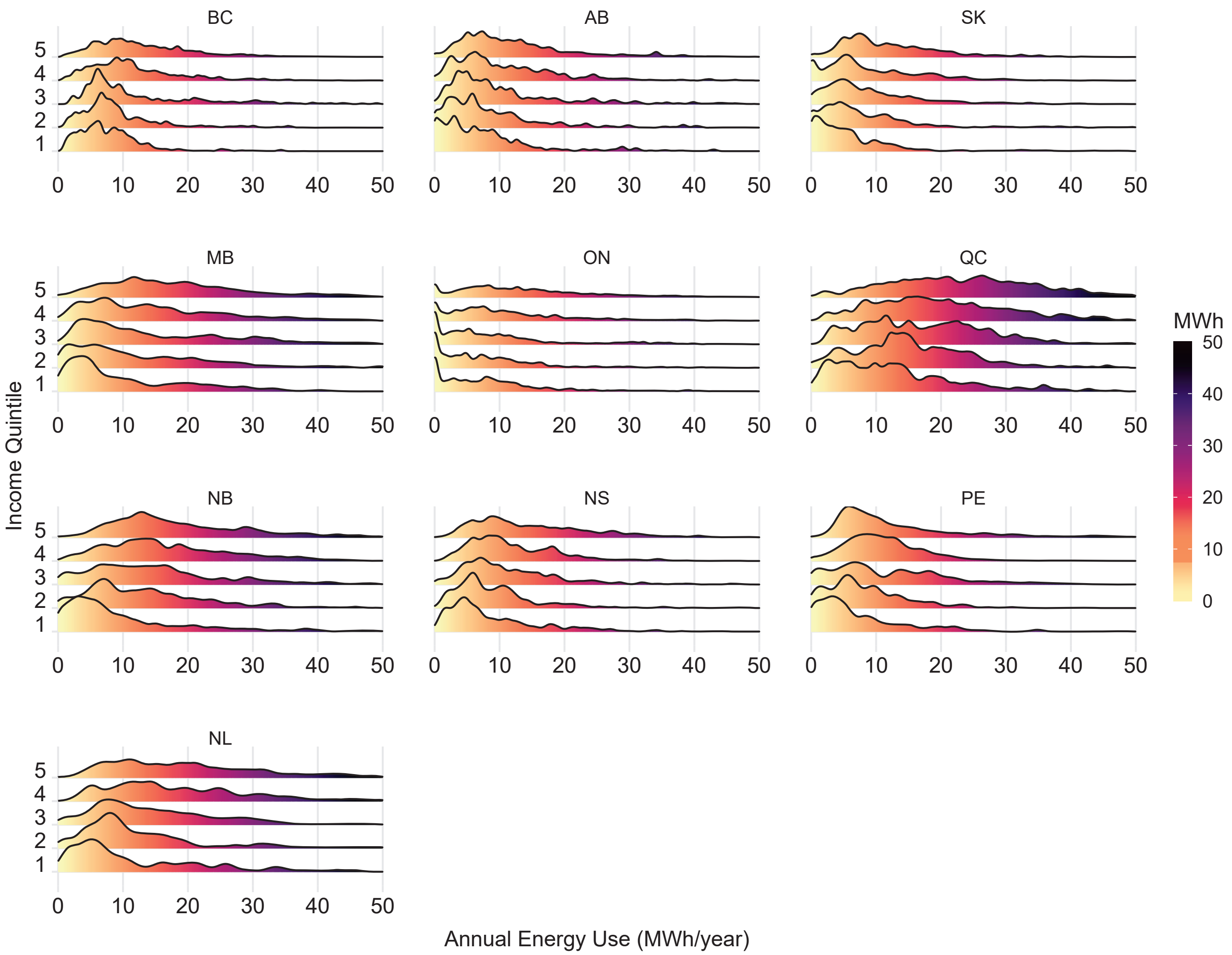
Note: The y-axis shows five income quintiles (equal groupings of households by income), where each quintile is 20 per cent of the population in each province by income. Quintile 1 is the lowest 20 per cent of the income distribution. The x-axis is annual electricity expenditure, in thousand 2022 constant dollars. We exclude households with no expenditure on electricity. The height of the curve shows the number of households that fall within a range along the x-axis. Electricity expenditure excludes commodity taxes. We use total income before taxes to define within-province income quintiles.

Figure 3 shows the distribution of households' annual electricity use in megawatt-hours (MWh) by province and income quintiles within each province, excluding households with no expenditure on electricity.[5] Most households consume 10 MWh or less per year. The pattern of distributions in Figure 2 differs from Figure 1 (expenditure), with a tighter distribution, particularly for lower-income households. Of note is that the "hydro provinces" that rely primarily on hydroelectricity—British Columbia, Manitoba, Quebec, and Newfoundland and Labrador—generally have a flatter and wider distribution of electricity use. This may reflect higher levels of existing electrification in these provinces.

[5] As we impute electricity use from expenditure, we are missing use from those households with electricity costs included in their housing costs.

Figure 3

2017 annual electricity use by province and income quintile (MWh)

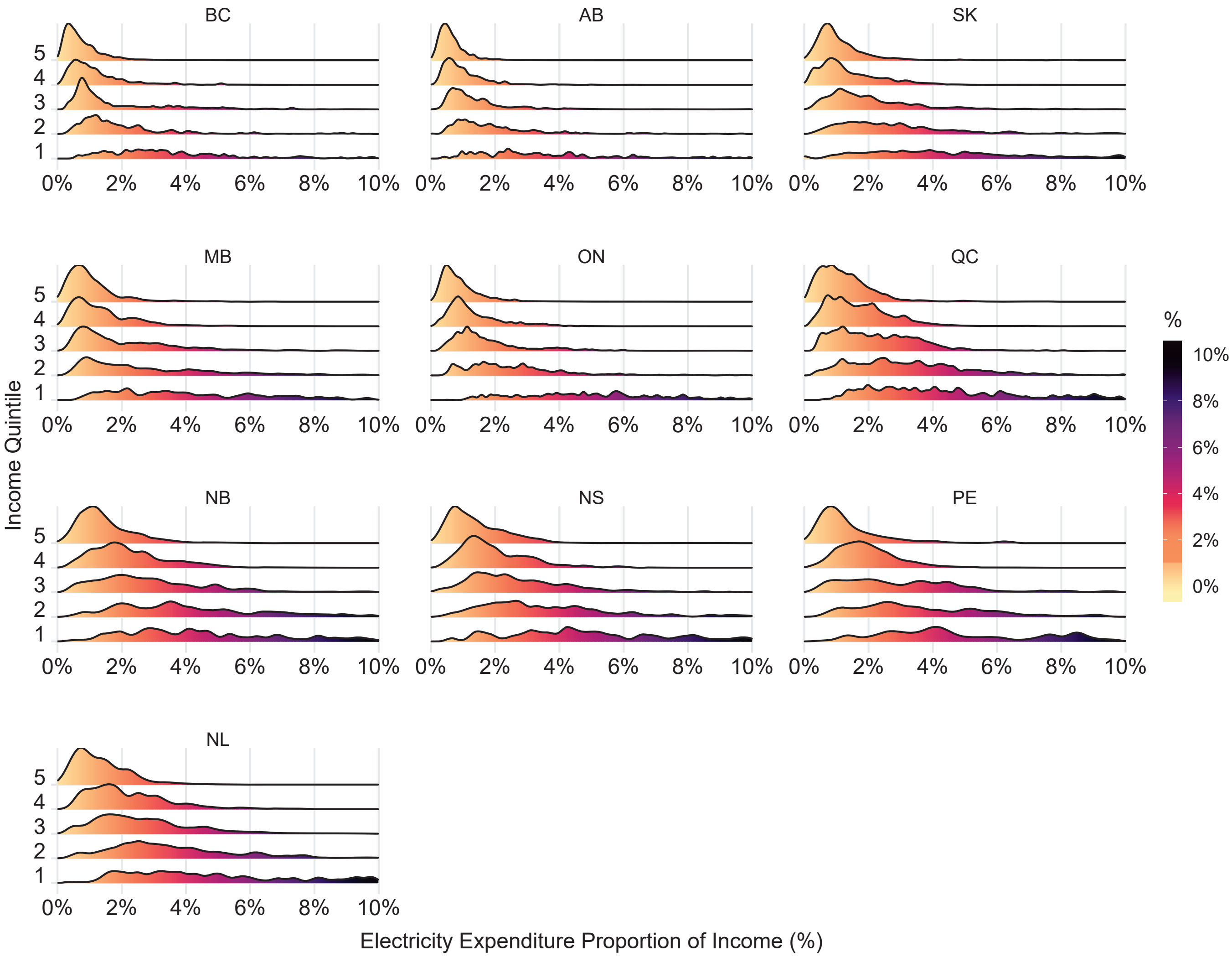


Note: The y-axis shows five income quintiles (equal groupings of households by income), where each quintile is 20 per cent of the population in each province by income. Quintile 1 is the lowest 20 per cent of the income distribution. We use total income before taxes to define income quintiles. The x-axis is annual electricity use, imputed from households' electricity expenditure and province-specific prices (see Table 1 in Appendix II for prices we use). We exclude households with no expenditure on electricity. The height of the curve shows the number of households that fall within a range along the x-axis.

Figure 4 shows households' annual electricity expenditure as a share of income by province and income quintiles within each province. This is a useful metric as it presents the relative burden of electricity expenditures. As a proportion of income, we see that electricity expenditures are a larger burden for lower income quintiles. Most of the higher-income households fall within the spending range of zero to two per cent of their income, while lower income quintiles spread across a range from two to 10 per cent and more. This implies that, all else equal, a proportional or uniform increase in electricity costs will affect lower-income households more. Without a similar increase in income, increases in electricity costs will potentially limit these households' ability to purchase other goods and services.

Figure 4

Annual electricity expenditure as a proportion of income

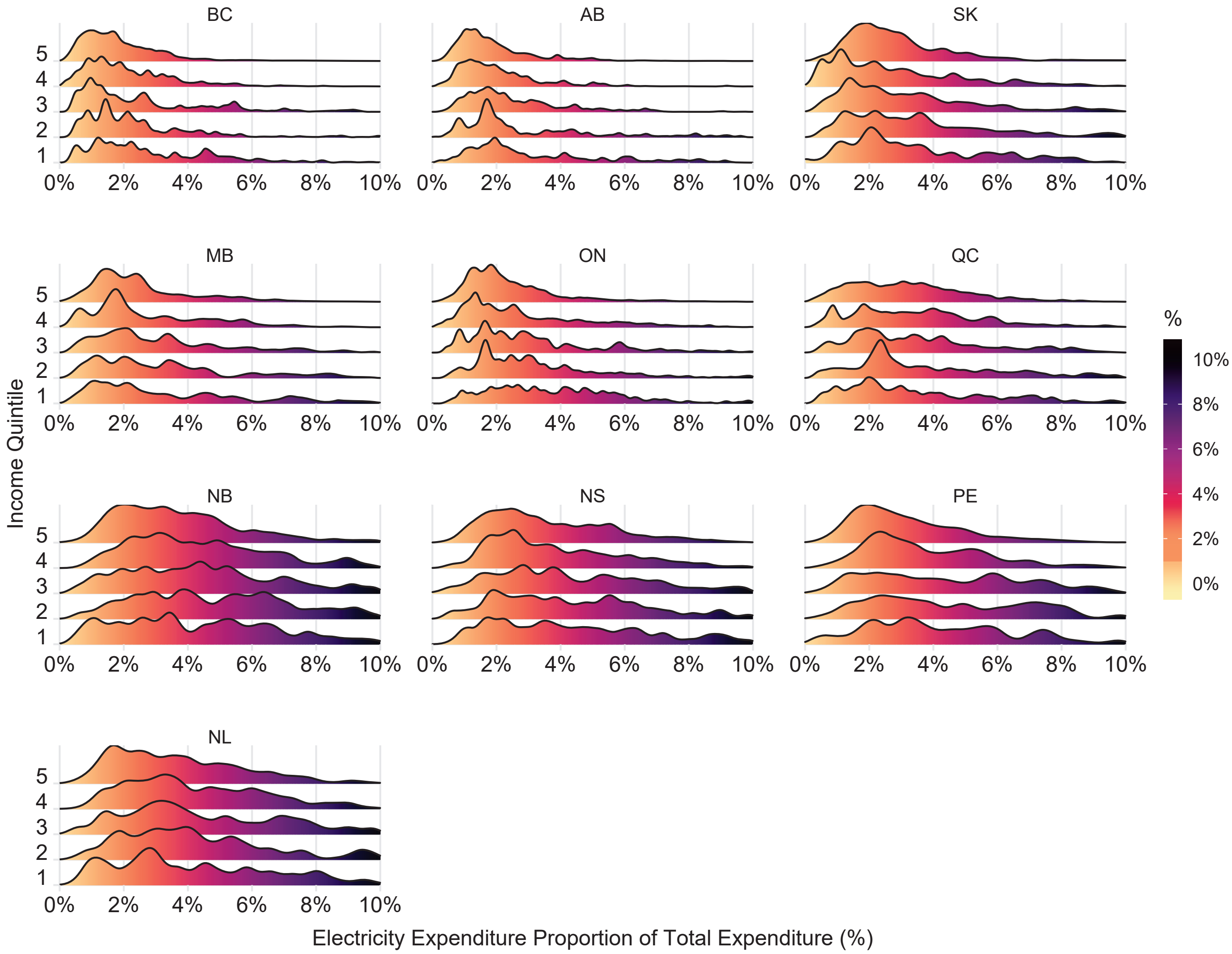


Note: The y-axis shows five income quintiles (equal groupings of households by income), where each quintile is 20 per cent of the population in each province by income. Quintile 1 is the lowest 20 per cent of the income distribution. We use total income before taxes to define income quintiles. The x-axis is annual electricity expenditure as a share of income. The height of the curve shows the number of households that fall within a range along the x-axis. We exclude households with no expenditure on electricity. Electricity expenditure excludes commodity taxes.

An alternative way to evaluate the burden of electricity costs is expenditure as a share of households' total expenditure (Figure 5). Some households may be retired, or temporarily have lower incomes (for example, parental leave), and comparing to total expenditure gives a richer sense of the relative cost burden (Poterba 1989). Using expenditure rather than income is closer to the lifetime burden of a specific type of expense. Here, electricity expenditures fall across income quintiles more equitably, compared to expenditure as a share of income in Figure 4. Importantly, however, there is still a persistent pattern of lower-income households spending more on electricity as a share of total expenditure compared to higher-income households.

Figure 5

Annual electricity expenditure as a proportion of total expenditure



Note: The y-axis shows five income quintiles (equal groupings of households by income), where each quintile is 20 per cent of the population in each province by income. Quintile 1 is the lowest 20 per cent of the income distribution. We use total income before taxes to define income quintiles. The x-axis is annual electricity expenditure as a share of income. The height of the curve shows the number of households that fall within a range along the x-axis. We exclude households with no expenditure on electricity. Electricity expenditure excludes commodity taxes.

Together, these plots show that while electricity expenditure increases with income, electricity is a higher share of both income and total expenditure for lower-income households. These households have less flexibility to adapt to increasing electricity prices. Even though modelling predicts total energy expenditure (on electricity, natural gas, gasoline, heating oil, etc.) will decrease over time (Dion et al. 2022), lower-income Canadians are vulnerable to increased costs from increased electrification in the absence of other policy intervention. We now turn to how net zero investments will affect system costs, electricity rates, and household costs.

NET ZERO AND ELECTRICITY COST PRESSURES

Here, we briefly cover our methods for and results from constructing expected electricity system investment costs, average generation costs, and the accompanying pressure on residential rates (both volumetric rates and fixed charges) and changes to household costs. We provide more detail on our methods in Appendix I.

Modelling electricity generation cost pressures

Electricity generation cost pressure is the expected change in average electricity generation cost due to changes in utility generation, distribution, transmission, and storage costs. These costs include fixed and variable elements. Fixed costs include investment costs (past, present, and future) for the electricity system itself, including power plants, wind and solar farms, hydroelectric facilities, transmission and distribution lines, and energy storage facilities. These investment costs are apportioned across users contemporaneously and over time, and funded primarily by debt. There are also fixed operations and maintenance costs that are required to keep the electricity system functioning. Variable costs include fuel for thermal plants, carbon pricing costs on fossil fuel use, and variable operations and maintenance costs.

To understand future generation costs, we use data from three electricity-system modelling groups: Canada Energy Regulator, Electric Power Research Institute, and ESMIA (Institut de l'énergie Trottier). These modelling groups created scenarios for electricity futures in provinces or regions throughout Canada. We use the modelling scenarios that are closest to achieving net zero greenhouse gas emissions by 2050. The modelling teams produce forecasts of costs that include projected capital costs for generation, transmission, and distribution; fixed operating and maintenance costs; variable operating and maintenance costs; and fuel costs.

We rely on these modelling outputs to project net zero investments in Canada's electricity system by province.[6] We do not include investment costs for making electricity systems more resilient to climate change,

[6] The EPRI model aggregates Quebec and Newfoundland and Labrador into one region, and Nova Scotia, New Brunswick and Prince Edward Island into another. We disaggregate the model results to individual provinces.

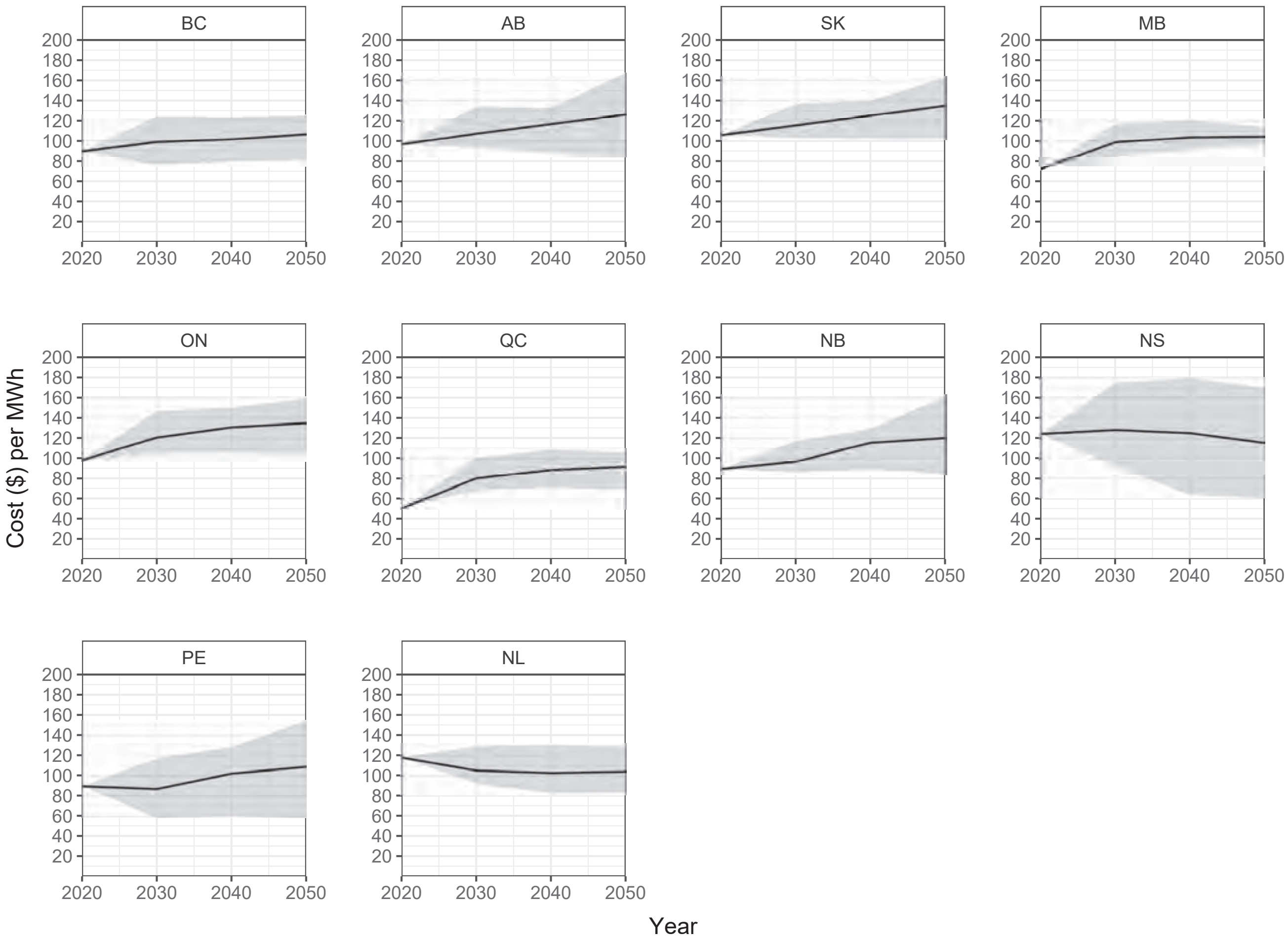
and so our analysis is a potential underestimate of total system costs between 2020 and 2050. Details on the specifics of the models and the assumptions are outlined in each modelling groups' published reports (Canada Energy Regulator 2021b; Electric Power Research Institute 2021; Langlois-Bertrand et al. 2021). The reports and assumptions are also summarised in Lee, Dion, and Guertin (2022). We augment the modelling outputs with existing and expected debt from provincial electricity utilities;[7] this creates a comprehensive measure of expected costs taking into account past investment costs. With this comprehensive cost data, we calculate average electricity-generation costs (inclusive of fixed and variable costs) for each model. These average costs are the estimated electricity generation costs for each province.

In Figure 6, we present our estimates of average electricity-system generation costs between 2020 and 2050. The black line is the mean of the three models' cost estimates, and the grey band reflects the maximum and minimum cost estimates in any given year. For most provinces, average electricity generation costs will likely increase, though there is also potential for costs to stay constant or decrease. The figure also demonstrates differences in current average generation costs across provinces, which also matters in considering distributional consequences. For example, Quebec and Manitoba have lower system costs. Even with new investments, the figure shows that generation costs in these provinces are only projected to increase to Ontario's current (2020) average cost. The effects of net zero investments will have differential cost implications for provinces. Thermal provinces—Alberta, Saskatchewan, New Brunswick, Nova Scotia, and Prince Edward Island as an importer of thermal electricity—whose electricity generation is currently heavily reliant on fossil fuels have the largest potential cost increases. These provinces require the greatest change in their electricity systems and so require relatively more investment. Importantly, the three models we rely on to estimate system cost increases differ in their assumptions. Specifically, some of the low-cost scenarios assume high adoption of low-cost renewables. The variation in assumptions creates larger ranges for thermal provinces, as there is more uncertainty about what the future electricity system will actually look like.

[7] This data is not comprehensive, but we identified long-term debt for the largest utilities in each province. Using these debt values, we calculate a debt per MWh annual charge by province and assign that charge to electricity rates.

Figure 6

Average electricity system generation cost, 2020 to 2050 in $/MWh (2022 constant dollars)



Note: Presents average generation cost changes over time. Average generation cost is the modelled generation cost including amortized debt, divided by total modelled generation. The black line is the mean of the three models' cost estimates, and the grey band reflects the maximum and minimum cost estimates in any given year.

Constructing residential average cost pressure

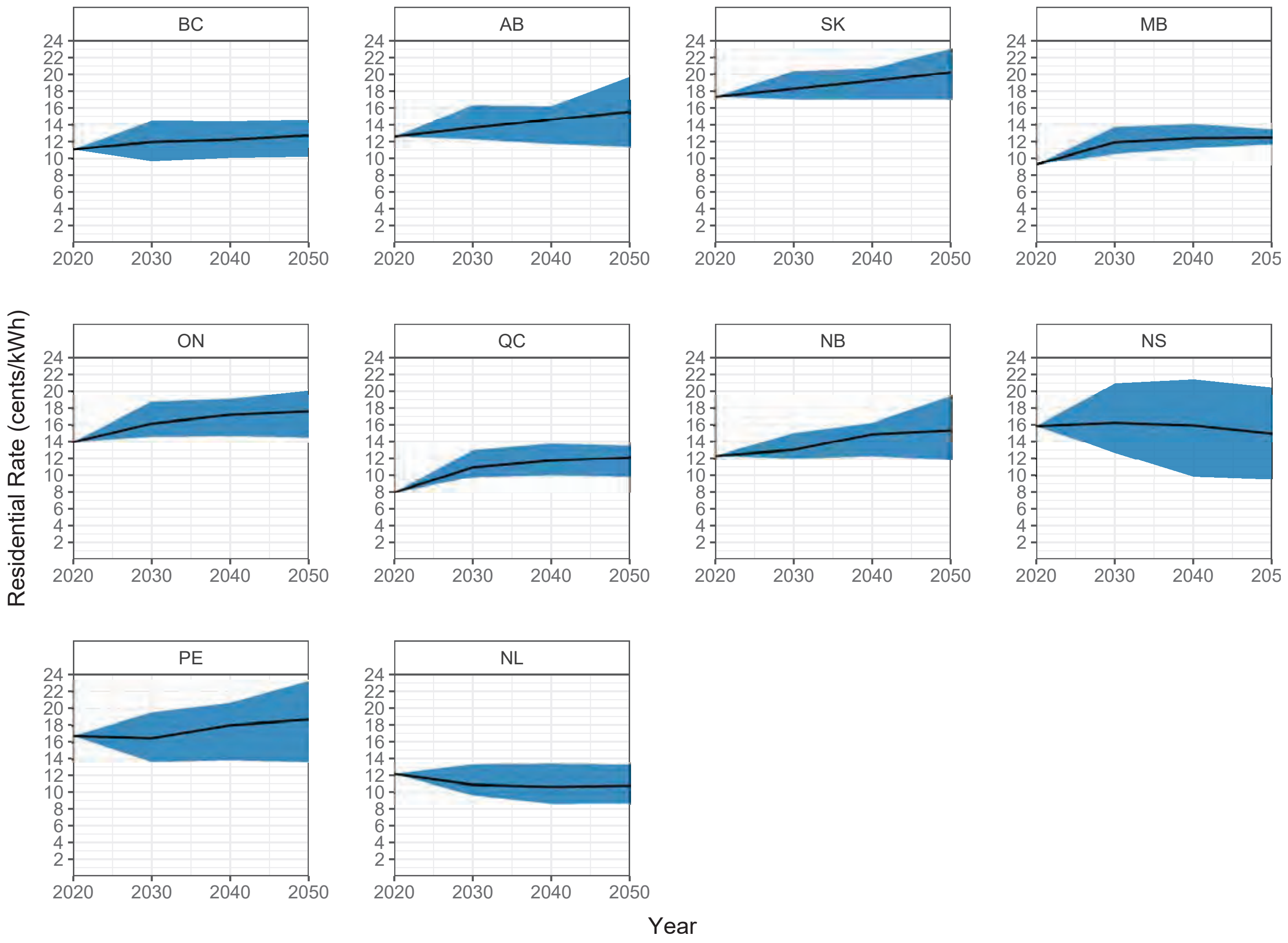
Residential cost pressure is the expected change in average residential electricity costs (both volumetric rates and fixed charges) resulting from changes in utility generation, distribution, transmission, and storage costs. This is distinct from electricity generation cost pressure as residential, commercial, and industrial ratepayers share electricity system costs, but costs are not necessarily apportioned equally across the rate classes.

Typically, residential ratepayers are slightly cross-subsidized by other ratepayer classes, in that commercial and industrial customers bear more of the costs of the electricity system relative to if costs were apportioned by share of use. Residential rates also have higher than average system generation costs due to administrative costs and other costs not included in the modelling. We adjust the cost projections in

Figure 6 by including a province-specific and constant cost-markup to account for differences in average system generation costs and average residential electricity costs. This markup is the difference between current average household electricity costs at today's rates and modelled average generation costs, and is model-specific. Figure 7 presents these changes, and has a very similar pattern to Figure 6. The black line is the mean of the three residential average cost estimates, and the blue band reflects the maximum and minimum estimates in any given year. The costs presented are average household electricity costs, and include both volumetric rates and fixed charges in the per-kWh value.

Figure 7

Residential average electricity cost pressures (constant 2022 cents/kWh), 2020 to 2050



Note: Presents the range of average residential electricity costs over time. We construct cost ranges by adding a province-specific rate inflation factor to average system cost calculated for each model and year. This rate inflation factor is calculated based on 2020 or most-recent-year comparisons of residential rates and system costs in each province. These average costs include both fixed charges and volumetric charges. The black line is the mean of the three models' cost estimates, and the blue band reflects the maximum and minimum cost estimates in any given year.

In the central estimate of the three models, the majority of provinces have minor electricity residential average cost increases, between two and four cents per kWh (2022 constant dollars). This is a small change over 30 years, and in many provinces, there is the potential that residential costs remain unchanged or even decrease. Importantly, the wide range in projected residential costs means that when holding use constant, total household costs could stay the same, decrease, or increase. With electrification, however, use is likely to increase. We turn to the joint effects in the next section.

Constructing household cost estimates

Total household costs depend on both prices and use. In the previous section we describe changes to average household electricity costs; here, we describe projected electricity use changes and the total effect on household bills. The three models project that households will, on average, use more electricity as they electrify vehicles and heating. Importantly, however, there is not a one-to-one switch in energy use; electric vehicles are significantly more efficient than internal combustion engines and heat pumps are significantly more efficient than natural gas or heating oil furnaces (Canada Energy Regulator 2021a; Natural Resources Canada 2021). The higher efficiency is part of the reason total energy expenditure will likely decline for Canadian households (see Figure 1). The increased efficiency resulting from electrification has a mitigating effect on increased electricity demand. Moreover, as shown above in Figure 7, residential average electricity costs may decline.

The three models forecast residential electricity demand and population change for each province or region. We use these data to calculate per capita electricity demand in current and future years (Figure 8) and construct a growth rate for residential electricity demand. In Figure 8, the black line is the mean of the three models' projections and the pink bands reflect the maximum and minimum per-capita demand forecasts. We assume that households' composition will not change significantly between 2020 and 2050, and use per-capita growth rates to construct growth rates in household electricity use by province. This assigns the same growth rate to different households within a province, with no differentiation by income.

Figure 8

Per capita residential electricity use, 2020 to 2050

Note: Presents per capita electricity use over time. The black line is the mean of the three models' use estimates, and the pink band reflects the maximum and minimum use estimates in any given year. Per capita electricity use projections are declining in Newfoundland and Labrador, but this appears to be due to modelling assumptions.

Finally, we combine electricity use from Figure 3 and the use changes from Figure 8 with household cost pressures from Figure 7 to construct changes in households' annual electricity expenditures. We present this in Figure 9, using 2021 prices to define "current" electricity costs and normalizing to 2020 to show changes in electricity expenditure relative to 2020.[8] As before, the black line in Figure 9 is the mean across the three models' results and the purple band shows the range between the mean of the high-cost modelling results and the mean of the minimum-cost modelling results in a given year.

The figure reveals different patterns in future household electricity expenditures across provinces. Households in Alberta, Saskatchewan, Manitoba, Ontario, and Quebec will spend more on electricity, though the scale of the increase differs substantially. In contrast, British Columbia and New Brunswick may have electricity expenditures stay constant or increase. Prince Edward Island and Nova Scotia have a large range of uncertainty—households' electricity expenditures may decrease or increase. Newfoundland and Labrador is the only province with an expected decline in household electricity

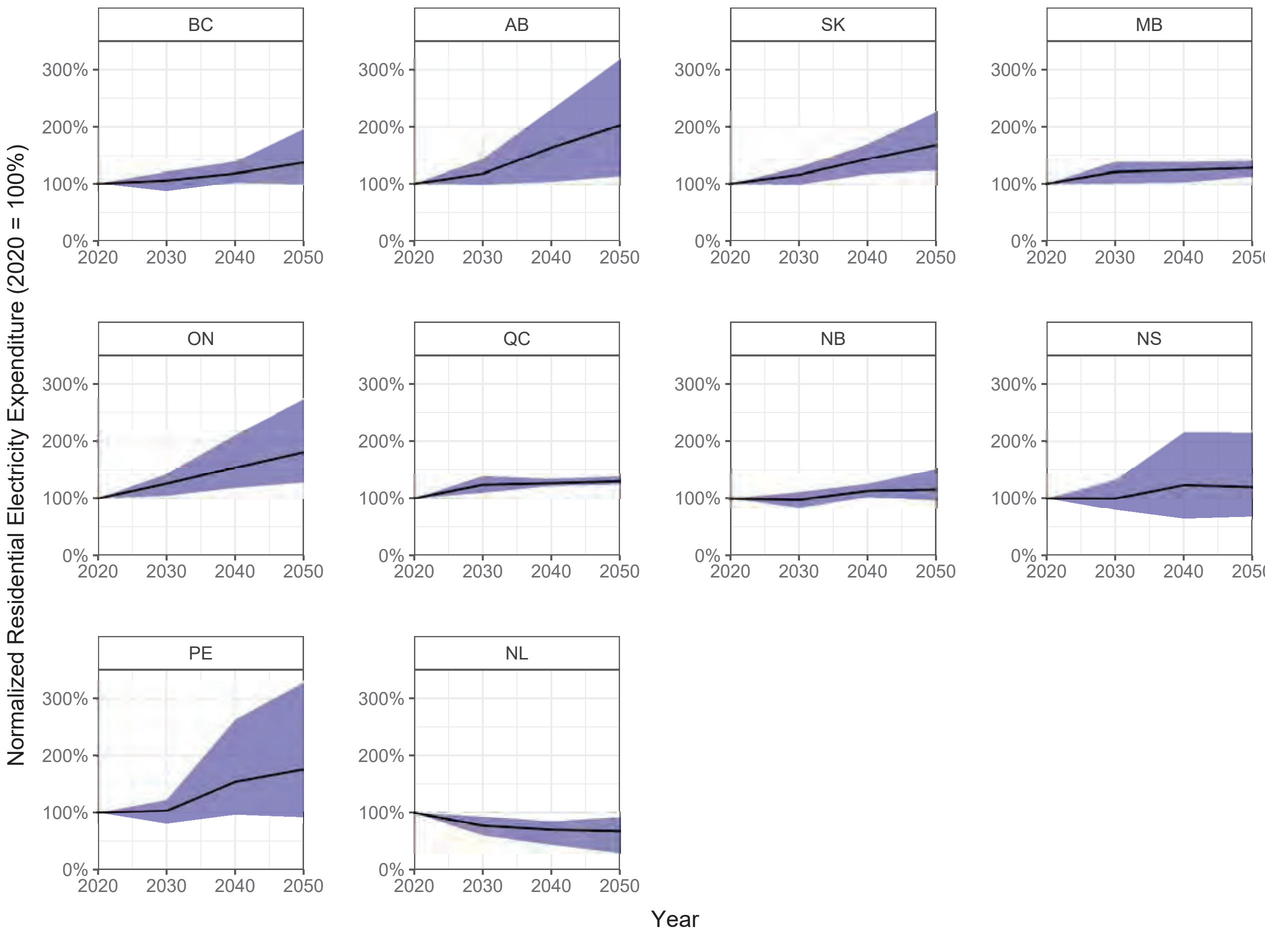
[8] We report 2021 volumetric rates and fixed charges by province in Appendix II, Table II.2.

expenditures. Several provinces—British Columbia, Saskatchewan, Ontario, and Nova Scotia—could have expenditures double, and Alberta and Prince Edward Island could even see electricity expenditures triple relative to 2020—though in all cases the lower bound has nearly unchanged expenditures.

However, the results presented in Figure 9 are an incomplete picture for two reasons, and should not be a *prima facie* cause for alarm. First, as we mention above, at the same time as electricity expenditure is rising, expenditure on fossil fuels will be falling, and so the expenditure changes displayed in Figure 9 are not net cost changes.[9] Second, electricity cost increases do not occur in a vacuum—we also expect incomes to grow. Nevertheless, for some provinces, these changes may be large and should provoke reflection on the ways that electricity system investments are funded and electricity rates designed. We turn now to a discussion of the distributional consequences of these electricity expenditure changes.

Figure 9

Range of changes to household electricity expenditures, 2020 to 2050



Note: Presents average household electricity expenditure changes over time, relative to 2020. This figure accounts for both use and cost changes. We impute base electricity use from 2017 expenditure using 2017 volumetric rates and fixed charges, and base electricity volumetric rates and fixed charges are from 2021. We scale both costs and use as described above. The black line is the mean of the three models' electricity expenditure estimates, and the purple band reflects the maximum and minimum expenditure estimates in any given year.

[9] Our scope is limited to assessing distributional consequences of electricity cost increases. Understanding net effects is an area ripe for future research.

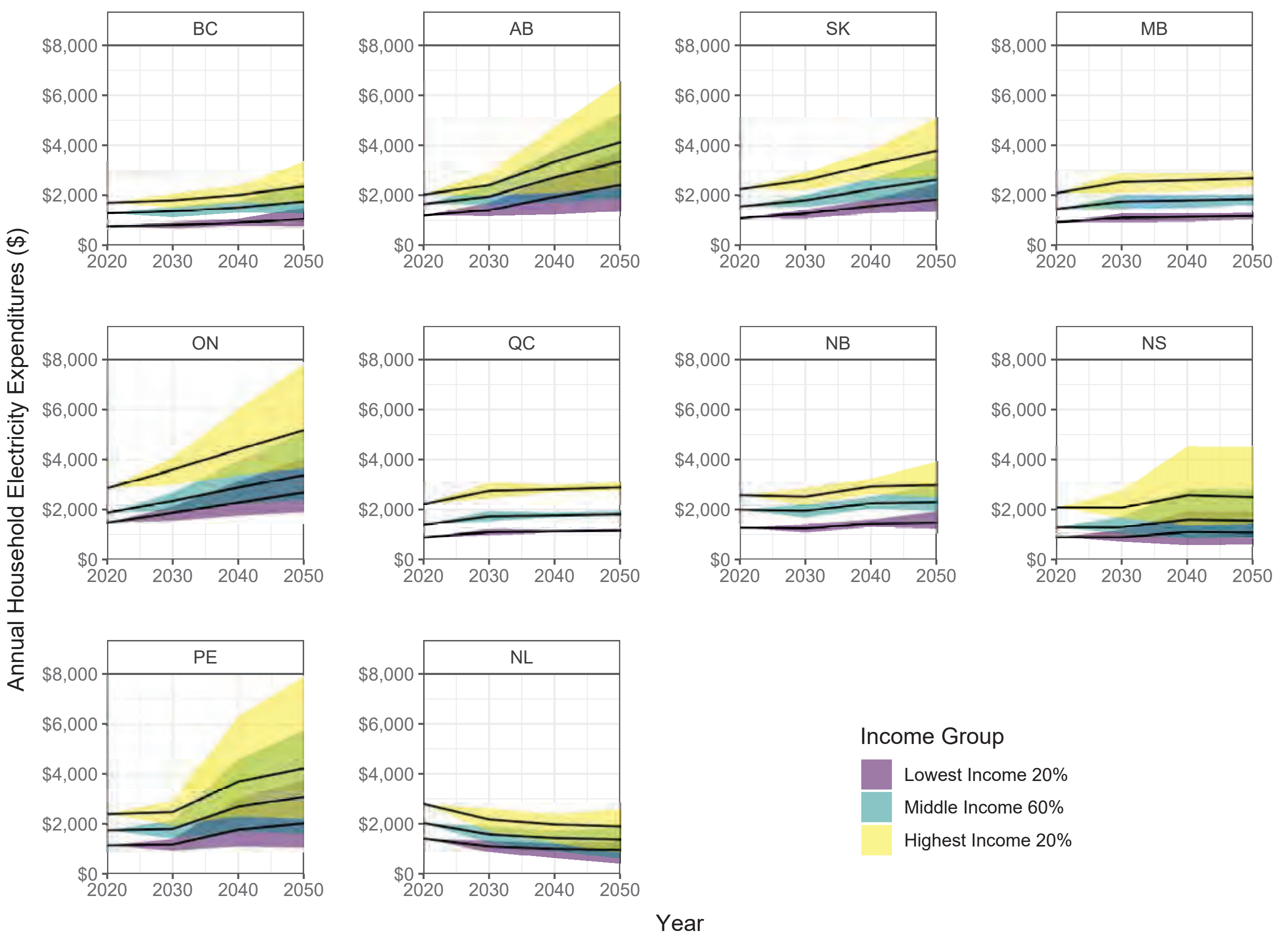
Net zero and electricity affordability: Distributional effects of electricity expenditure changes

As shown above, income groups have different electricity use and expenditure patterns. This can translate to differential distributional effects of electricity expenditure changes, particularly for more vulnerable (lower-income) households. In this section, we use the SPSD/M microdata to explore these distributional consequences, using the electricity expenditure changes in Figure 9. We apply the same relative increase to each household's current electricity expenditures, and present expenditure changes between 2020 and 2050 (Figure 10).[10] This simulates what the changes in residential use and residential rates will mean for households at different income levels. The most uncertainty for households' expenditures is in Alberta, Saskatchewan, Ontario, Nova Scotia, and Prince Edward Island.

Figure 10

Residential annual electricity expenditures by income group, 2020 to 2050

(2022 constant dollars)



Note: The y-axis shows forecast annual electricity expenditure in 2022 constant dollars for the bottom and top income quintiles and the middle three quintiles (equal groupings of households by income), where each quintile is 20 per cent of the population in each province by income. We use total income before taxes to define income quintiles. Electricity expenditure excludes commodity taxes. Baseline electricity expenditure is imputed 2017 use at 2021 volumetric rates and fixed charges. The range for each quintile is based on the mean annual household cost for each quintile and reflects the range in modelling studies. The top of the range is the quintile's mean from the model with the highest expenditure, and the bottom of the range is the quintile's mean for the model with the lowest expenditure. The black line is the within-quintile mean, averaged across all three models.

[10] The 2020 expenditure is based on imputed 2017 electricity use inflated to 2020 dollars.

To put these costs in perspective and understand the change in purchasing power, we evaluate household electricity expenditure relative to 2021 incomes in Figure 11. The figure shows average within-quintile expenditure as a share of 2021 income without income growth to cleanly identify the potential affordability challenge of electricity expenditure changes and the required income growth to keep current shares constant. The figure shows that lower-income households are most vulnerable to expenditure increases, and that the inequality in electricity expenditures will increase. Specifically, higher-income households' electricity expenditure as a share of income stays constant between 2020 and 2050. As incomes are expected to increase, this implies these households are likely to spend a smaller share of their income on electricity. In contrast, the bottom 20 per cent of each province's income distribution is particularly vulnerable to electricity expenditure increases. This quintile spends far more as a share of income and for some provinces this proportion will double. The issue is particularly acute for lower-income households in Alberta, Saskatchewan, Ontario, New Brunswick, and Prince Edward Island. Even in hydro provinces—British Columbia, Manitoba, and Quebec—lower-income households have a larger proportional increase in electricity expenditure between 2020 and 2050.

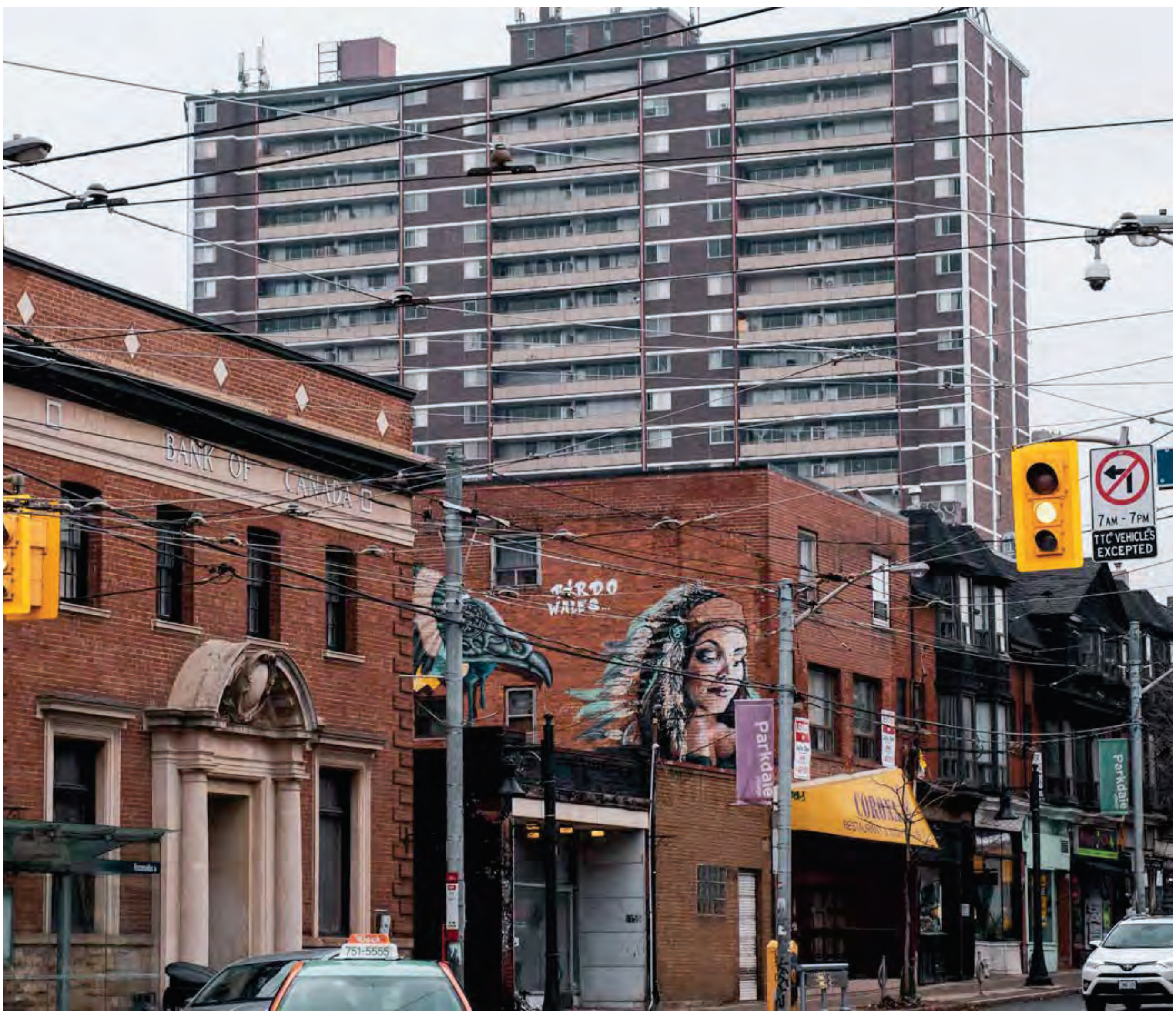


Figure 11

Total electricity expenditure as a proportion of 2021 income

Note: We separate households into five income quintiles (equal groupings of households by income), where each quintile is 20 per cent of the population in each province by income. Quintile 1 is the lowest 20 per cent of the income distribution. We use total income before taxes in 2021 to define income quintiles. Baseline electricity expenditure is 2017 use at 2021 volumetric rates and fixed charges, and excludes commodity taxes. We assume no income growth to clearly show the equity consequences of increasing household electricity expenditure.

The patterns in Figure 11 are concerning as recent evidence suggests income inequality in Canada is increasing (Green, Riddell, and St-Hilaire 2017), intergenerational mobility is decreasing (Connolly, Haeck, and Lapierre 2021), and wages are growing more slowly than economic growth and productivity (Ashwell 2021; Greenspon, Stansbury, and Summers 2021; Williams 2021). If past patterns hold, income growth for lower-income households may be insufficient to compensate for increases in electricity bills, exacerbating the current burden and relative inequity. Policymakers may wish to consider additional policy action to address this problem and specifically insulate lower-income households from net zero transition costs. We turn to these policy options in the next section.

POLICY OPTIONS FOR FUNDING NET ZERO ELECTRICITY SYSTEM INVESTMENTS

We demonstrate above that an electricity system supporting net zero emissions targets in Canada will likely increase electricity expenditures for some households, assuming a status quo approach to funding the electricity system. While this increase occurs in the context of falling energy costs overall (Dion et al. 2022), funding the costs of electricity investments differently could affect this distributional incidence. To this end, we explore options to mitigate cost pressures on low-income households.

Rate-design choices and government supports will have different distributional consequences. We compare several counterfactual scenarios modifying rate design and reducing system investment costs through tax financing. Our reference case is the status quo described above, using 2021 electricity rates and estimated future rates with current rate design. We assess the relative cost burden faced by households under five counterfactual scenarios. The first three scenarios are alternative rate-design options, while the latter two are alternatives for funding net zero investments. We distinguish between the two approaches in our discussion below. For ease of interpretation we present distinct policy scenarios, but these policy choices are not mutually exclusive and it may be desirable to adjust both rate design and system funding.

Rate design choice and equity

In this section, we explore how utilities can change rate structures to address the issue of distributional equity, and other concerns. An acknowledged challenge in rate design is the apportionment of fixed system costs into volumetric rates and fixed charges (Borenstein 2016). In most provinces the majority of fixed costs are folded into volumetric charges (cents per kWh), making the monthly or annual fixed charges users pay on their electricity bills smaller than would be the case if they truly reflected fixed costs. This increases volumetric charges above the true marginal cost of generation, and reduces incentives to switch to electric vehicles, electric heat, and electric industrial processes (Borenstein, Fowlie, and Sallee 2021).

The disjoint between volumetric prices and marginal costs makes distributed solar generation a challenge for utilities: solar self-generators under net-metering plans receive the volumetric retail rate of electricity, while only saving the utility the marginal cost of generation. This means that solar self-generators are cross-subsidized by other customers. A potential solution is increasing fixed charges to ensure solar self-generators pay the real system costs for having the grid as a backup (Borenstein 2011; Borenstein, Fowlie, and Sallee 2021). This has the benefit of shifting electricity volumetric rates closer to marginal cost, which is more efficient, and desirable for encouraging electrification of vehicles and buildings. However, while transmission and distribution as a fixed charge is desirable from an efficiency and rate design perspective, it creates equity challenges due to the uniform and fixed nature of the fixed charges. Specifically, an increase in fixed charges is regressive and negatively affects low-income ratepayers. If fixed charges increase to address the cross-subsidization of solar and move volumetric rates closer to marginal cost, then utilities can consider means-tested fixed costs to address equity concerns.

We examine three scenarios for different approaches to fixed charges:

1) **Transmission and distribution as fixed charge:** This scenario modifies the reference case and bases the fixed monthly charge on the cost of transmission and distribution; all remaining costs are covered via residential volumetric electricity rates. Specifically, we remove amortized transmission and distribution costs from total system costs and assign these costs as uniform fixed charges.[11] The fixed monthly charge is added to household costs but not reflected in the volumetric price per kWh. This rate design could improve incentives for electrification by reducing volumetric rates and help rates better approximate actual marginal generation costs, but it would affect cost incidence.

2) **Means-tested fixed charge (GST targeted):** This scenario modifies the uniform fixed-charge scenario by making fixed charges income-dependent and increasing with income. The fixed charge matches the progressivity of the GST. We model this by calculating the proportion of GST paid by each income quintile in Canada, and then designing uniform within-quintile fixed charges that match those proportions. For example, the lowest income quintiles across all provinces pay 10 per cent of GST in aggregate, and we apportion this percentage of transmission and distribution costs to the lowest income quintile, and split the proportion equally across households in the quintile. This scenario involves cross-subsidization of electricity-system fixed costs between income groups within a province.

3) **Means-tested fixed charge (personal income tax targeted):** Like policy 2) above, this policy modifies the uniform fixed-charge scenario by making fixed charges income-dependent and increasing with income. The fixed charges match the progressivity of the federal personal income tax system. We model this by calculating the proportion of personal income taxes paid by each income quintile in Canada, and then designing uniform within-quintile fixed charges that match those proportions. For example, the lowest income quintiles across all provinces pay 0.5 per cent of personal income taxes in aggregate, and so we apportion this percentage of transmission and distribution costs to the lowest

[11] To calculate the volumetric rates we remove fixed transmission and distribution cost components and then divide the remaining system costs by aggregate household electricity use to find an adjusted volumetric rate.

income quintile, and split the proportion equally across households in the quintile. Conversely, the highest income quintile households pay 63 per cent of personal income taxes and so are charged correspondingly higher fixed charges on these modelled electricity bills. This scenario also involves cross-subsidization of electricity-system fixed costs between income groups within a province.

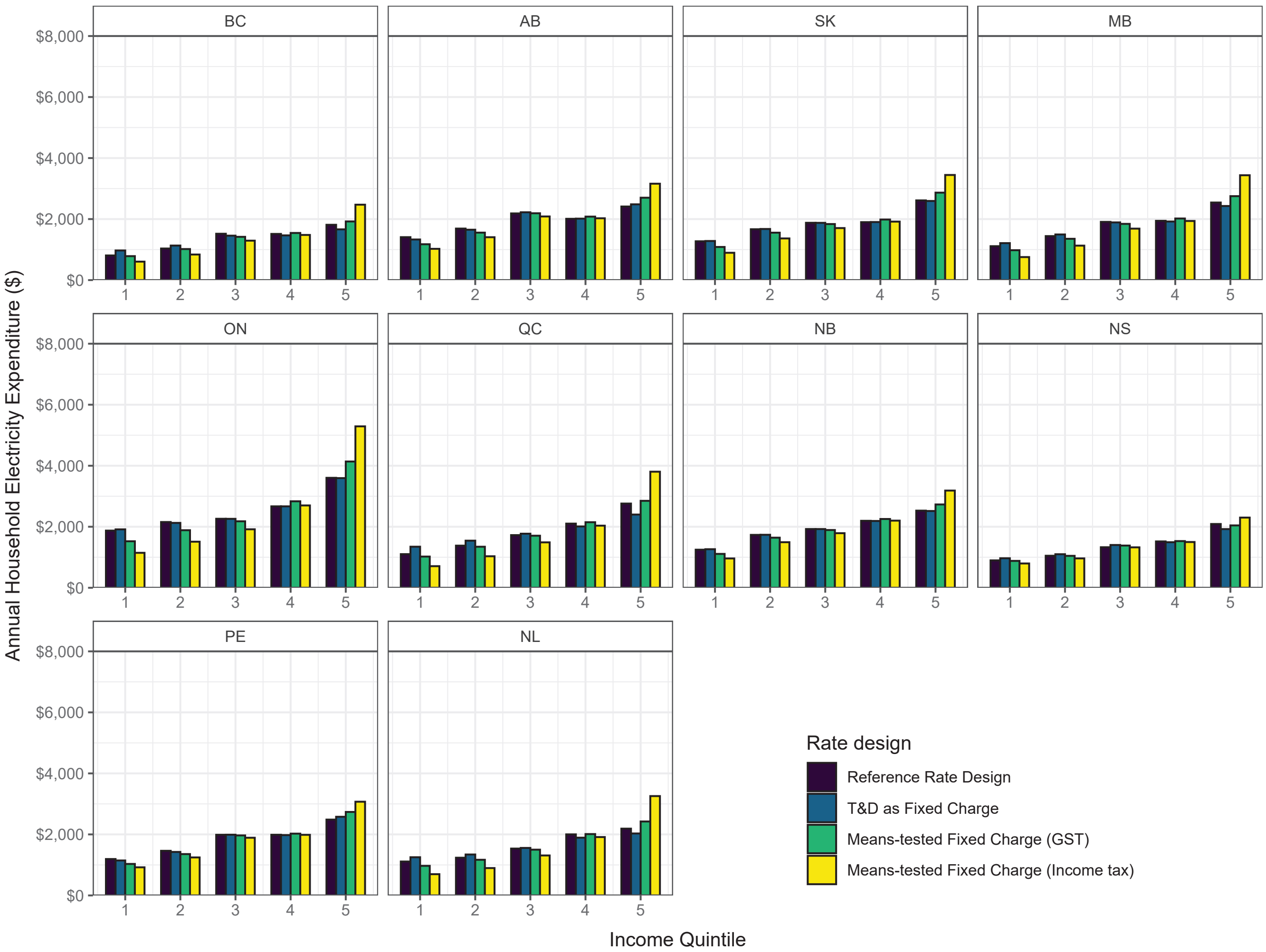
Figure 12 shows within-province quintile-average total household electricity costs in 2030 for the different rate-design scenarios. Figure 13 shows 2040 results, and Figure 14 shows 2050 results. The pattern across scenarios remains the same, though costs increase over time. All rate design scenarios show total household costs increase with income. In most provinces, the alternative scenarios generate roughly equivalent costs for the third and fourth income quintiles. The most visible differences in costs and the effect of rate-design choices on costs are in the first and fifth quintiles—the lowest-income and highest-income households. In most provinces, households in the lowest two quintiles face higher costs when transmission and distribution is a fixed charge relative to the reference case. The higher-income households are generally better off with the uniform fixed charge relative to the reference case. This is not surprising, as a uniform fixed charge is more burdensome on lower-income households with lower use. Exceptions are Alberta, New Brunswick, and Prince Edward Island, due to a relatively close alignment with our estimated transmission and distribution costs and existing fixed charges. Some utilities have higher fixed charges, perhaps reflecting a desire to charge ratepayers for transmission and distribution independently of volumetric rates.[12] For these provinces, our modelled adjustments in rate design have very little effect on total household electricity expenditures.

The figures show the means-tested fixed charge matched to the progressivity of income taxes is the most effective policy for lowering lower-income households' total costs; this results in higher-income households cross-subsidizing electric system costs for lower-income households in each province. The means-tested fixed charge pinned to the GST is also progressive, but expenditures are higher for all but the fifth income quintile.

[12] Alberta has relatively high fixed charges, and Prince Edward Island has somewhat high fixed charges. In contrast, British Columbia only has a daily fixed charge and all other residential charges are volumetric (Bishop, Ragab, and Shaffer 2020).

Figure 12

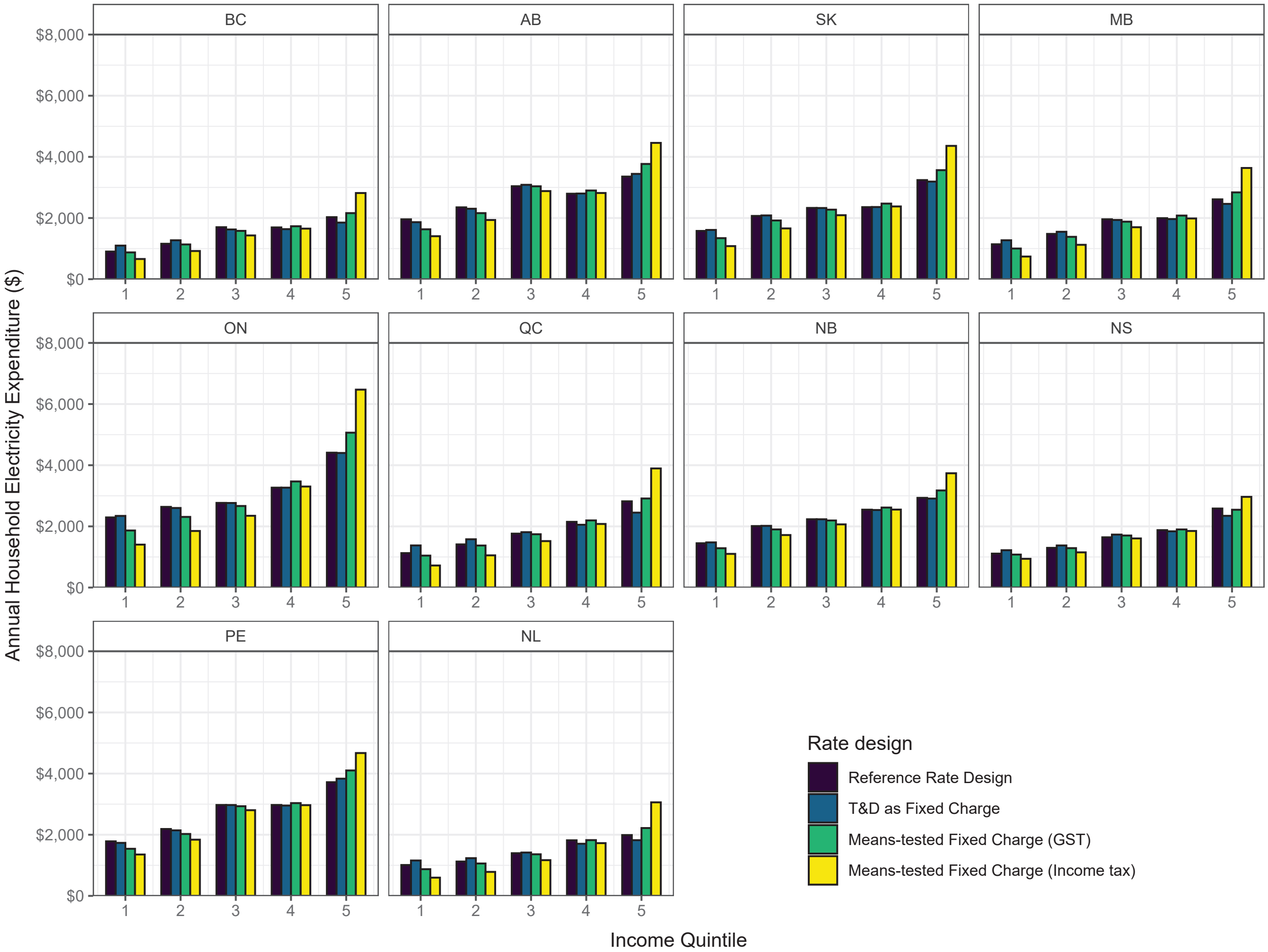
2030 total annual household electricity expenditures under different equity and rate-design scenarios (2022 dollars)



Note: Presents total annual household electricity expenditure in 2030 by income quintile, for different rate-design scenarios. This figure accounts for both use and cost changes; the rate-design scenarios modify how system costs are apportioned between the reference case (existing rate formats) and alternative fixed charges. Cost and use changes are based on the mean of the three modelling studies.

Figure 13

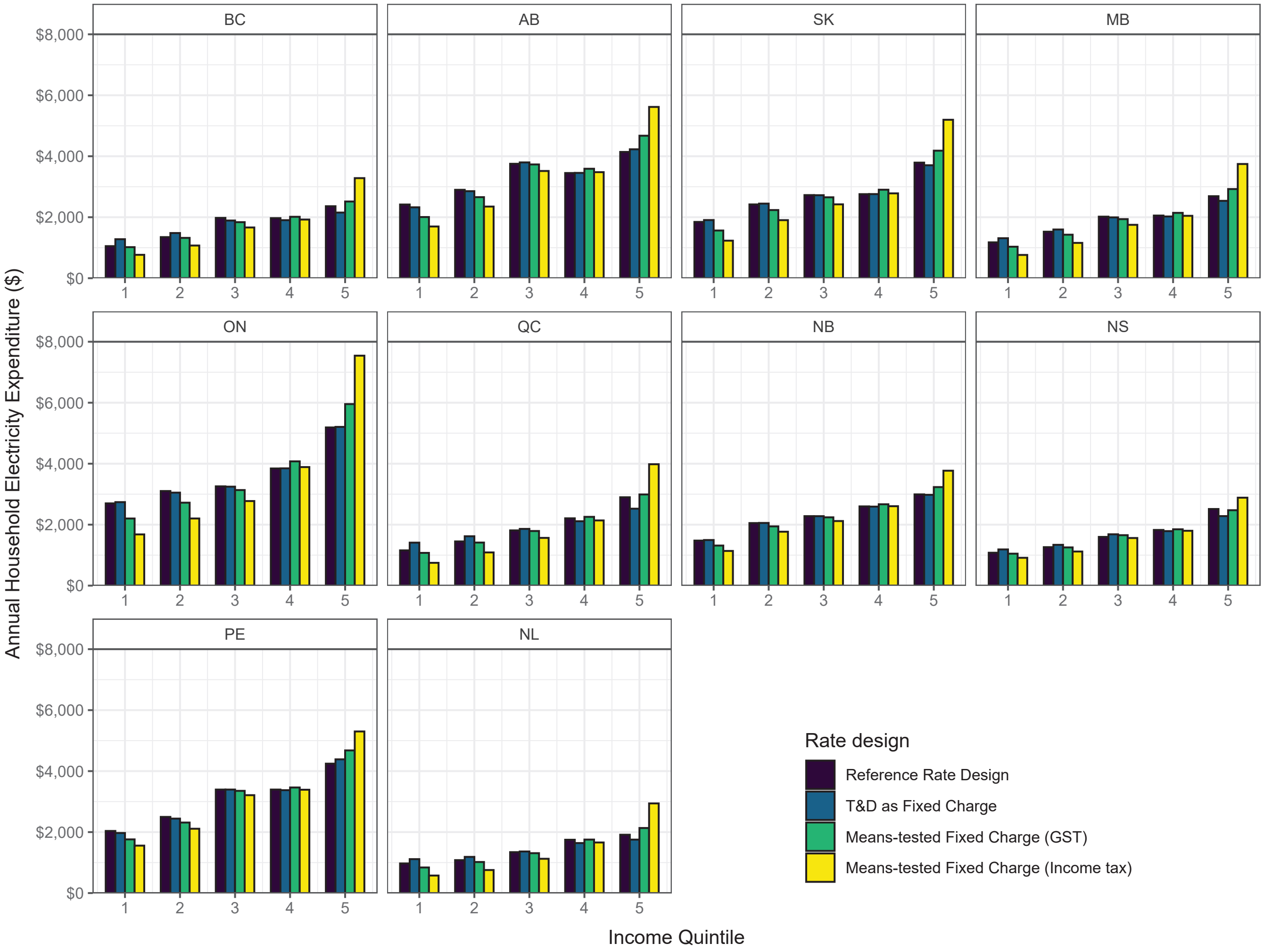
2040 total household electricity expenditures under different equity and rate-design scenarios



Note: Presents total annual household electricity expenditure in 2040 by income quintile, for different rate-design scenarios. This figure accounts for both use and cost changes; the rate-design scenarios modify how system costs are apportioned between the reference case (existing rate formats) and alternative fixed charges. Cost and use changes are based on the mean of the three modelling studies.

Figure 14

2050 total household electricity expenditures under different equity and rate-design scenarios



Note: Presents total annual household electricity expenditures in 2050 by income quintile, for different rate-design scenarios. This figure accounts for both use and cost changes; the rate-design scenarios modify how system costs are apportioned between the reference case (existing rate formats) and alternative fixed charges. Cost and use changes are based on the mean of the three modelling studies.

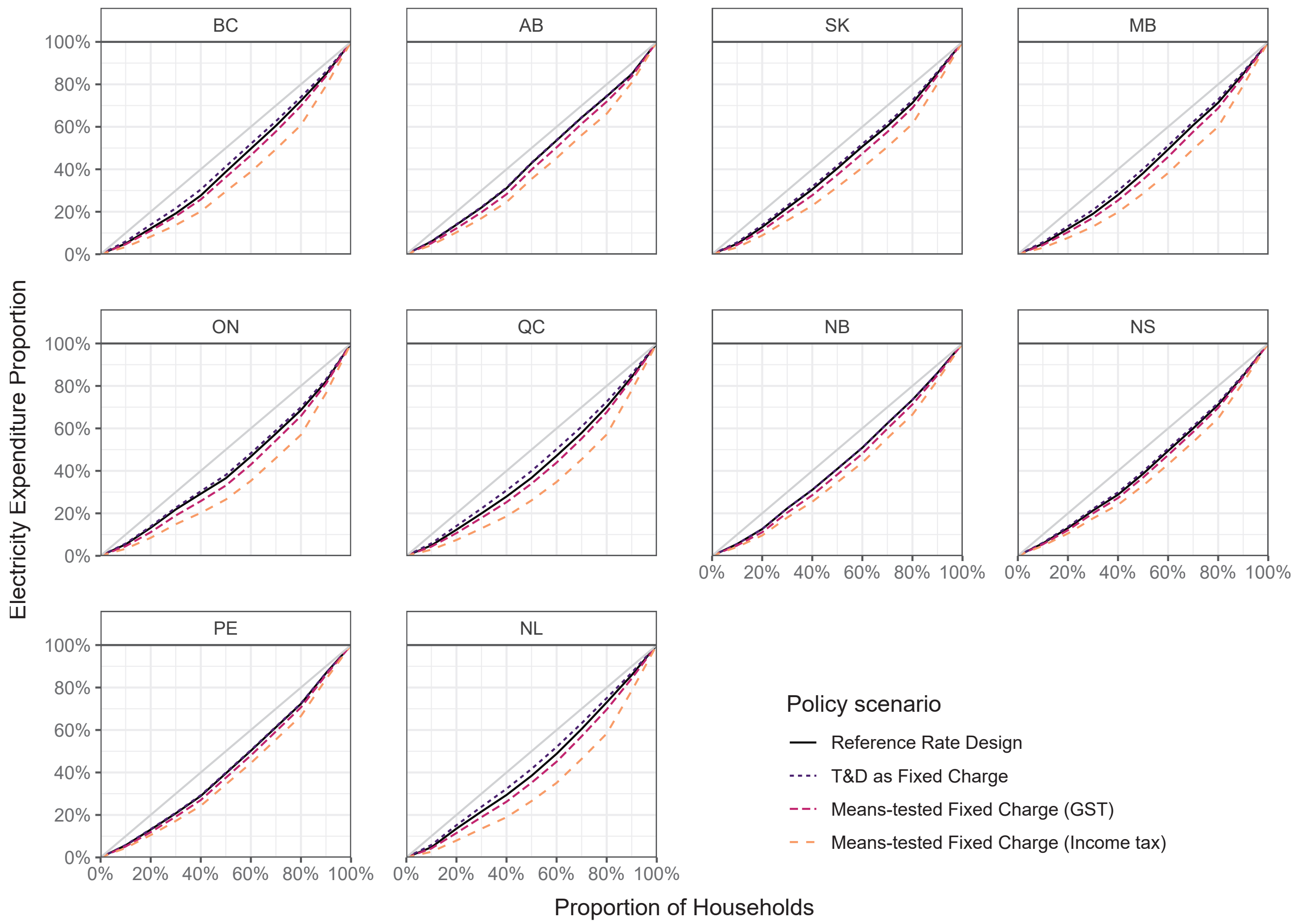
Figure 15 presents a Lorenz curve for the different rate-design scenarios; Lorenz curves show the distribution of costs against the population distribution ordered from lowest income to highest income households. This curve has a different interpretation from a standard Lorenz curve as it presents expenditures rather than income on the y-axis.[13] The thin grey line is the line of perfect equality (the 45-degree line), where electricity costs are equal across the population and independent of income and use. Lines further below the 45-degree line are more progressive, representing larger shares of total electricity costs paid by households that use more electricity (Levinson and Silva 2022).[14]

[13] Lorenz curves are typically used to show the distribution of income or wealth, but can be applied to show the distribution of costs.
[14] This is the opposite interpretation of a standard, income-based, Lorenz curve, where moving away from the line of perfect equality implies a less progressive (more regressive) income distribution with higher income inequality.

Figure 15 shows that the choice of rate-design scenario matters the most for the top and bottom 20 per cent of the income distribution. Basing the fixed charge on the cost of transmission and distribution moves volumetric rates closer to the marginal cost of electricity generation, and improves the price signal to users. However, it increases costs for lower-income households, which may have limited ability to absorb these increased costs or may tip into energy poverty.[15] Means-testing fixed charges is an effective way of mitigating the distributional and equity implications of fixed charges. Matching the fixed charges to the income tax system results in the most progressive rate system.

Figure 15

Lorenz curve for average household electricity costs by rate design option and province, 2050



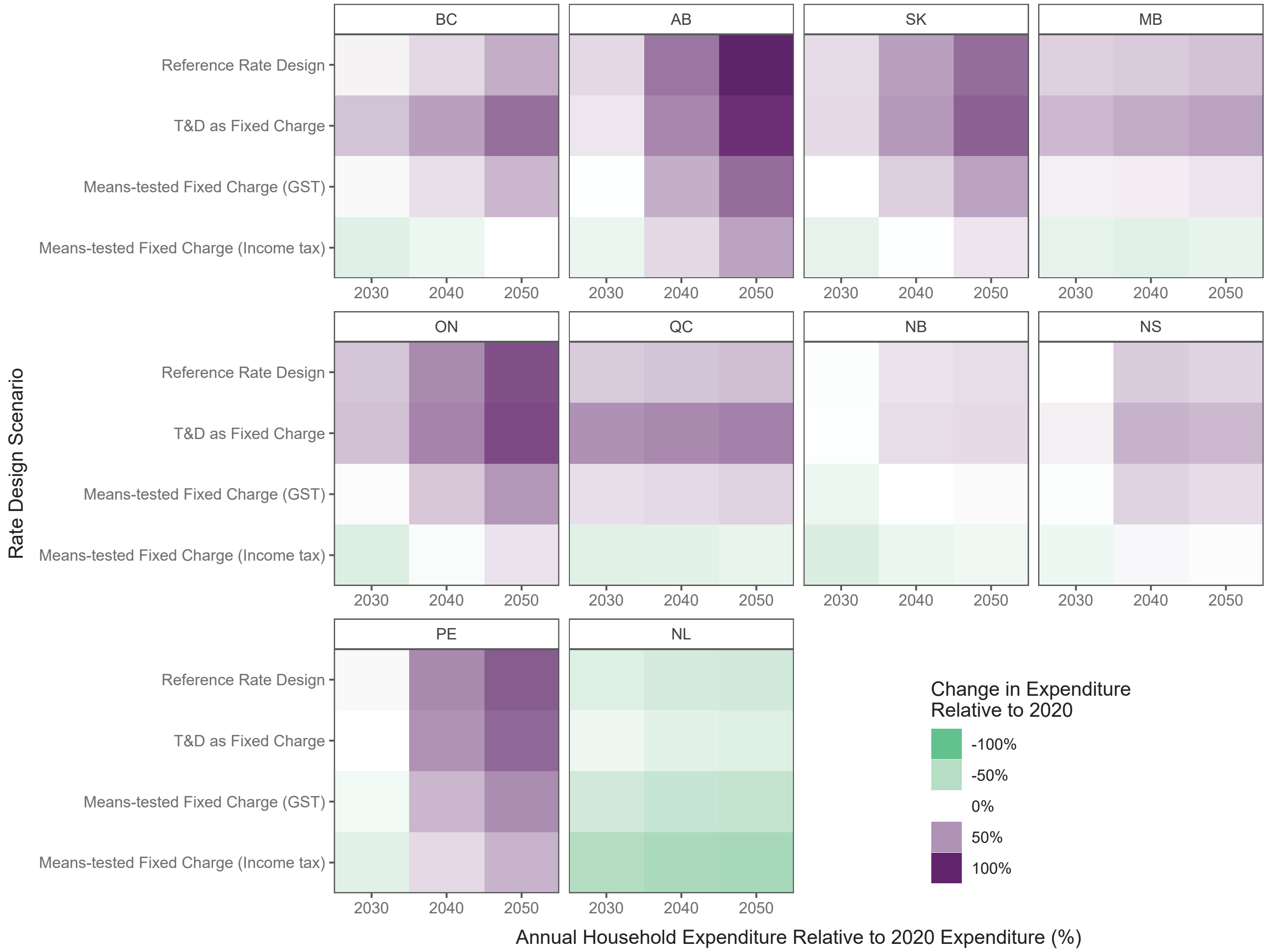
Note: Presents the Lorenz curve for household electricity expenditures, plotting proportion of expenditure by household (y-axis) against cumulative share of households arranged from lowest to highest incomes (x-axis). The thin grey line is the line of equality, where electricity expenditure is equal and independent of income and use. Lines further below the line of perfect equality are more progressive rate designs.

[15] Energy poverty is households' inability to afford energy services; it may manifest as a heat-or-eat dilemma, self-imposed brownouts for financial reasons, or keeping home temperature at lower-than-comfortable room temperature. For a discussion of definitions of energy poverty, see Shaffer and Winter (2020).

Figure 16 presents the lowest income quintile's average total household electricity expenditures in 2030, 2040, and 2050 relative to expenditures in 2020 for the different rate-design scenarios. A means-tested fixed charge is most effective at insulating low-income households from potential rate increases; when the fixed charge is pegged to the progressivity of the federal income tax system, total expenditures decline relative to 2020 for low-income households in most provinces. Expenditure increases are particularly acute for households in Alberta, Saskatchewan, and Ontario due to the major system investments to be compliant with net zero and larger forecast increases in electricity usage. Overall, insulating lower-income households from cost pressures will require rate-design changes or some other cost-offset mechanism. We turn to alternative funding approaches in the next section.

Figure 16

Lowest income quintile's average annual household electricity expenditures relative to 2020 under different equity and rate scenarios



Note: Presents the percentage change in average annual electricity expenditures in 2030, 2040, and 2050 relative to 2020 under different rate-design structures, for the lowest income quintile in each province. The reference case is status quo rate-design systems in each province. .

Electric federalism: Options for funding net zero investments

Addressing climate change is a responsibility for all of society, not just electricity ratepayers (Borenstein, Fowlie, and Sallee 2021; Kanduth and Dion 2022). Government can acknowledge that achieving net zero emissions is a social and political goal, and can partially fund the electricity system's transition to ensure the move does not unduly increase electricity costs. This approach spreads the burden of net zero investments—generation, transmission, distribution, and storage—amongst a larger group.

We model 50 per cent government funding of system investment costs (reducing both volumetric rates and fixed charges for households), and compare the net household financial results of provincial versus federal funding via personal income tax increases.[16] Our choice of 50 per cent government funding is arbitrary and meant to illustrate the distributional consequences of direct government subsidies of net zero investments rather than a prescriptive policy position. We use the existing rate structure to calculate aggregate household electricity costs for each province, and then model the rates required if government funded 50 per cent of new system investments. The investment required varies by province and by modelling team. Provinces that must invest more receive proportionately more government funding, and reduce their electricity system costs by more. For each province we scale fixed charges by the change in total electricity system costs that result from 50 per cent funding of new investment. For example, if new investment comprises 50 per cent of electricity system costs, and it is reduced by 50 per cent, then total cost is 75 per cent of what it would have been otherwise. We then scale fixed charges by multiplying by 0.75. After we subtract the new

[16] Recall that the cost pressures we model are for residential electricity rates and use only. Implicit in our analysis is that commercial and industrial customers will also bear their share of system costs. We do not assume any government support of commercial and industrial electricity consumers.

fixed charges from the total system cost covered by residential customers, we divide the remaining costs by aggregate household electricity use in that province to calculate the new required volumetric rate. This means we reduce both fixed charges and volumetric rates equally. The two scenarios are:

1) **Reduced bills and federal tax increases:** finances the 50 per cent of new investments in generation, transmission, distribution, and storage costs via contemporaneous federal personal income tax increases. This scenario subsidizes the net zero electricity-system investments and involves cross-subsidization between income groups; when federal taxes are used to fund system investments there is also cross-subsidization across provinces. Specifically, provinces with higher investment costs receive greater federal funding as the 50 per cent subsidy is within-province costs. The income tax increase parameters are reported in Appendix II: Supplementary Tables.

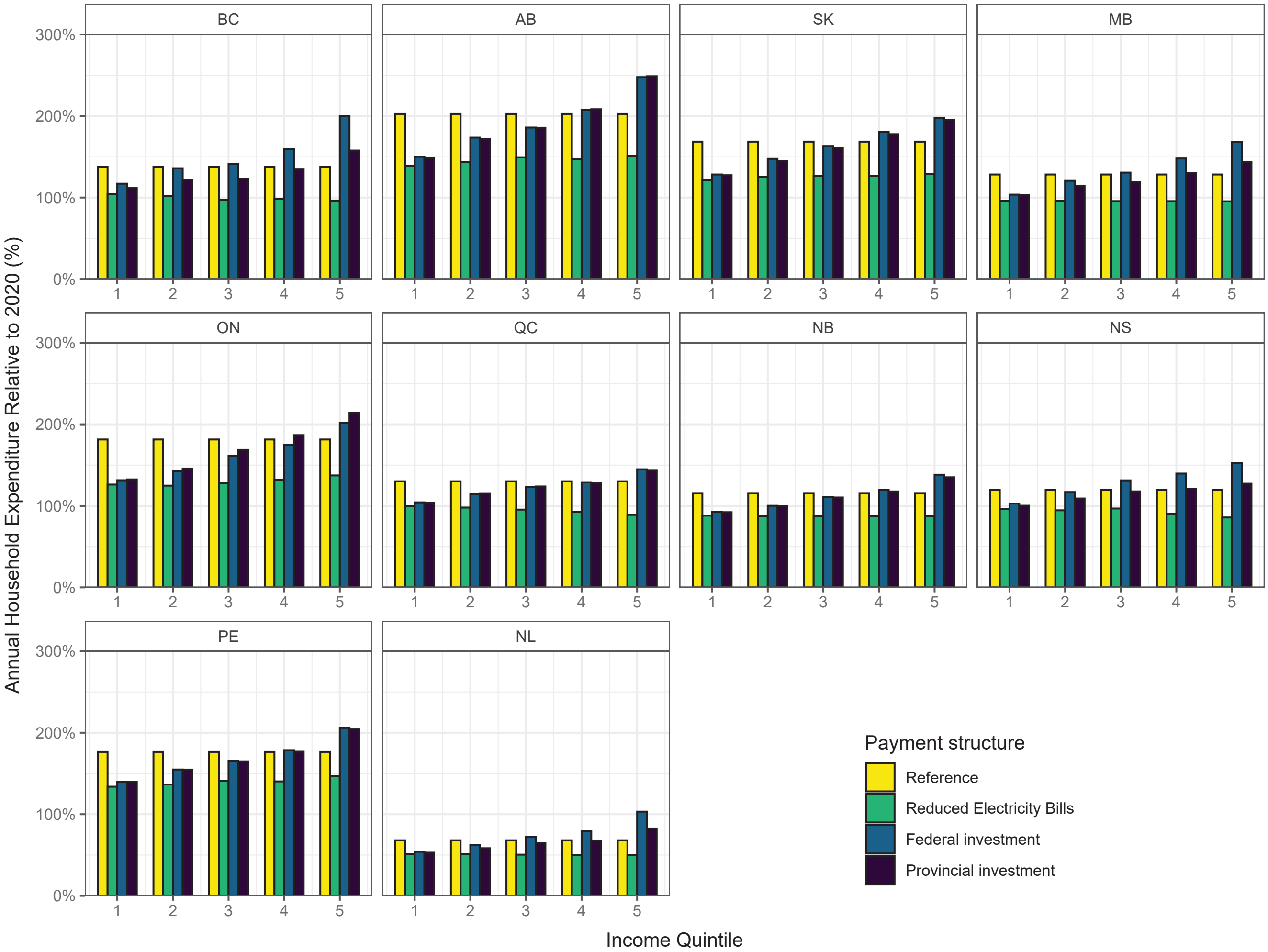
2) **Reduced bills and provincial tax increases:** finances the 50 per cent of generation, transmission, distribution, and storage costs via contemporaneous provincial personal income tax increases. This scenario subsidizes the net zero electricity system investments and involves cross-subsidization between income groups within provinces. We report the income tax increase parameters in Appendix II: Supplementary Tables.

We also show the effect on electricity expenditures, exclusive of income tax changes ("Reduced electricity bills"). This demonstrates how government funding would affect electricity expenditures relative to the reference case ("Reference").

Figure 17 shows 2050 total household costs relative to 2020 under the two system funding scenarios, inclusive of the income tax burden from funding 50 per cent of system costs via federal or provincial personal income taxes. The reference case, shown by the yellow bar, is a province-specific uniform scaled increase in costs across all households. The green bar shows the change in electricity bills without adding income taxes; as with the reference case, costs scale uniformly within provinces. Notably, lower-income households (the bottom two quintiles) are better off when system costs are subsidized through tax changes, and the highest-income households are worse off. Importantly, however, there are stark differences in the relative burden between provinces. Provinces with predominantly low-emission grids like British Columbia, Quebec, and Manitoba have higher costs when federal funding subsidizes system costs relative to provincial funding. In contrast, thermal provinces—Alberta, Saskatchewan, New Brunswick, and Prince Edward Island (as an importer of thermal electricity)—have very similar costs under provincial versus federal income-tax financing. Federal income-tax financing shifts costs from higher-emissions provinces to lower-emission provinces. Moreover, the provinces that contribute more to federal income taxes fund more, in relative terms, another source of cross-subsidization.

Figure 17

2050 total household electricity expenditures relative to 2020 under system funding scenarios

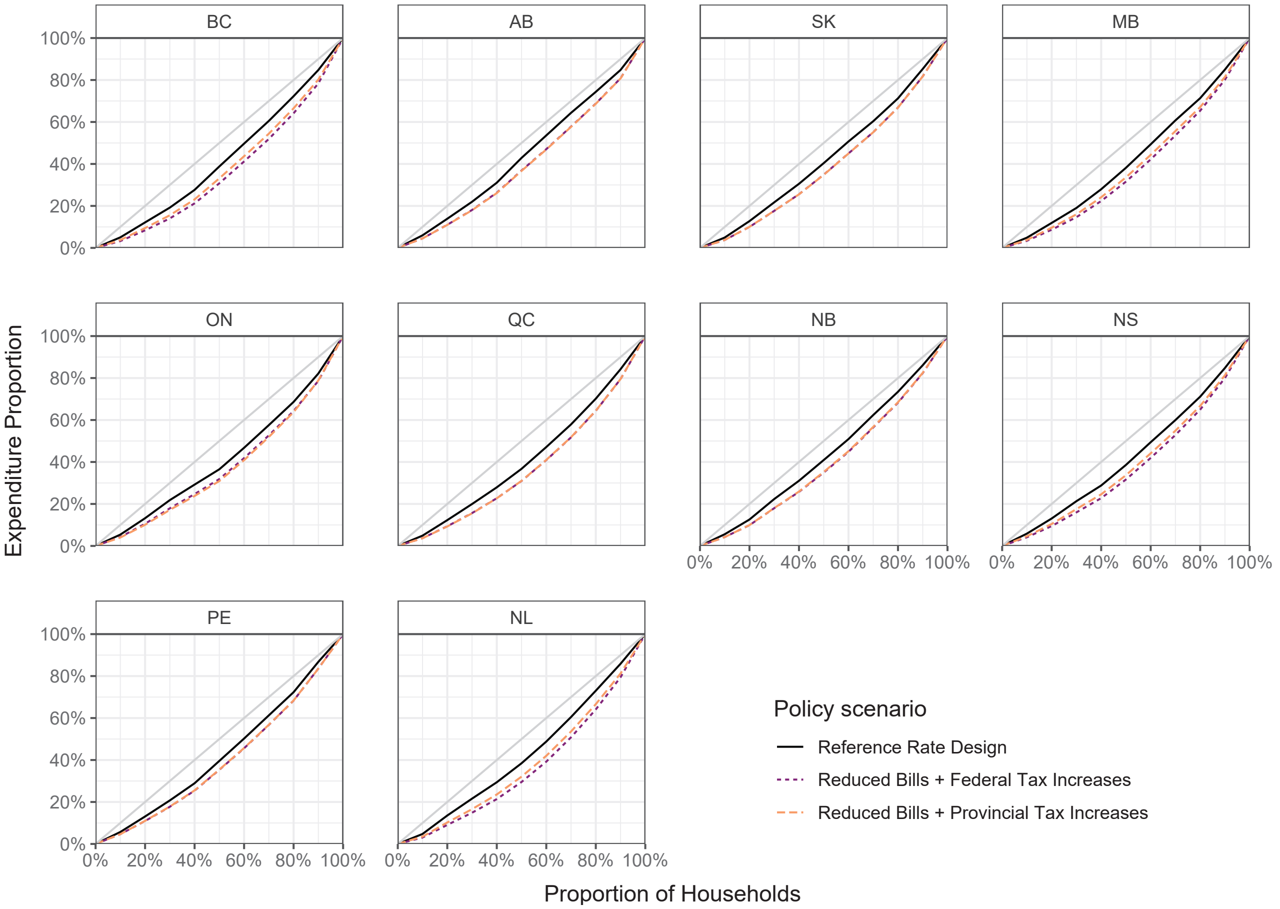


Note: Presents the percentage change in average annual household electricity expenditures in 2050 relative to 2020 under different rate-design structures, for income quintiles in each province. The figure accounts for both changes in costs and changes in use. The reference case (yellow) is status quo rate-design systems in each province, with uniform scaled cost increases across the income distribution. The reduced electricity bills scenario shows the effect on electricity expenditures exclusive of income tax increases. Federal investment assumes 50 per cent of new investments in generation, transmission, distribution, and storage costs within a province are funded by federal personal income tax changes. Provincial investment assumes 50 per cent of new investments in generation, transmission, distribution, and storage costs within a province are funded by provincial personal income tax changes.

Figure 18 shows the Lorenz curve for the two tax-funded scenarios against the reference case or status quo. As expected, funding new system investment costs with increases to income taxes increases the progressivity of electricity costs. Interestingly, for most provinces there is very little difference between federal funding and provincial funding via income taxes. However, for British Columbia, Manitoba, Nova Scotia, and Newfoundland and Labrador, a federal tax increase is slightly more progressive. In contrast, in Ontario federal funding is very slightly less progressive than provincial funding. Also of note in Figure 18 is that the Lorenz curves for the two funding scenarios are quite close to the reference case Lorenz curve. This indicates that funding net zero system investments via government funds rather than through rates has a limited effect on the progressivity of household electricity costs. This is in contrast to Figure 15, where a means-tested fixed charge had a larger progressivity improvement for some provinces. This indicates rate design is likely a more powerful tool for addressing equity concerns as it is a more targeted and precise policy tool; tax-base funding of system investments benefits all ratepayers whereas means-tested fixed charges explicitly target distribution concerns.

Figure 18

Lorenz curve for average household electricity expenditures by system funding option and province, 2050



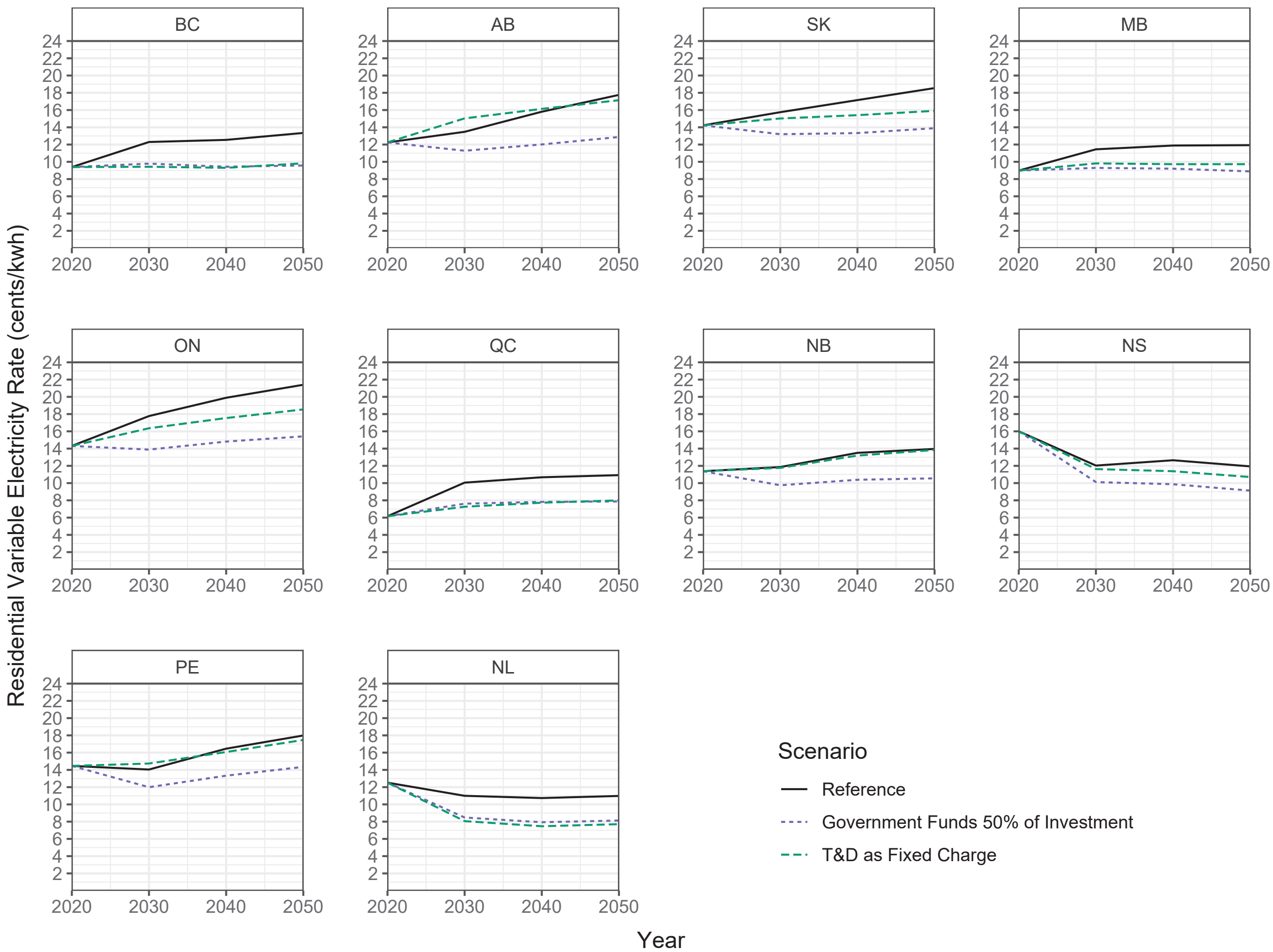
Note: Presents the Lorenz curve for total household electricity expenditures under different system funding scenarios, plotting proportion of costs by household (y-axis) against cumulative share of households arranged from lowest to highest incomes (x-axis). The thin grey line is the line of equality, where electricity expenditure is equal and independent of income and use. Lines further below the line of perfect equality are more progressive distributions of electricity costs. The electricity costs are based on the mean of the three modelling studies.

While rate design changes may be better suited to addressing progressivity of electricity costs, government funding of new system investments is a powerful tool for reducing electricity rate pressures. Figure 19 shows variable (per kWh) electricity costs under three different scenarios: the reference case, where investment costs are included in variable rates; the *system-funding* scenario where government funds 50 per cent of investment costs; and the rate-design scenario where transmission and distribution costs are allocated to households' bills as a province-specific uniform fixed charge (not means-tested).

For the majority of provinces, the reference case has the highest volumetric electricity rates and government funding 50 per cent of costs results in the lowest variable rates. However, in some provinces, like Alberta, New Brunswick, and Prince Edward Island, the fixed charge scenario is largely the same as the reference case. As noted above, in our discussion of Figure 12 through Figure 14, exceptions are in provinces with a relatively close alignment with our estimated transmission and distribution costs and existing fixed charges. In contrast, several provinces—British Columbia, Quebec, and Newfoundland and Labrador—have nearly identical variable electricity costs in the two alternative scenarios. This is due to these provinces' lower investment requirements to meet zero-emissions electricity targets. Hydro provinces are well-positioned with legacy emissions-free assets. The difference across provinces is also due to variation in modelling assumptions around high adoption of low-cost renewables, with more uncertainty about what the future electricity system will actually look like.

Figure 19

Volumetric electricity rates (cents/kWh) under different rate-design and system-funding scenarios

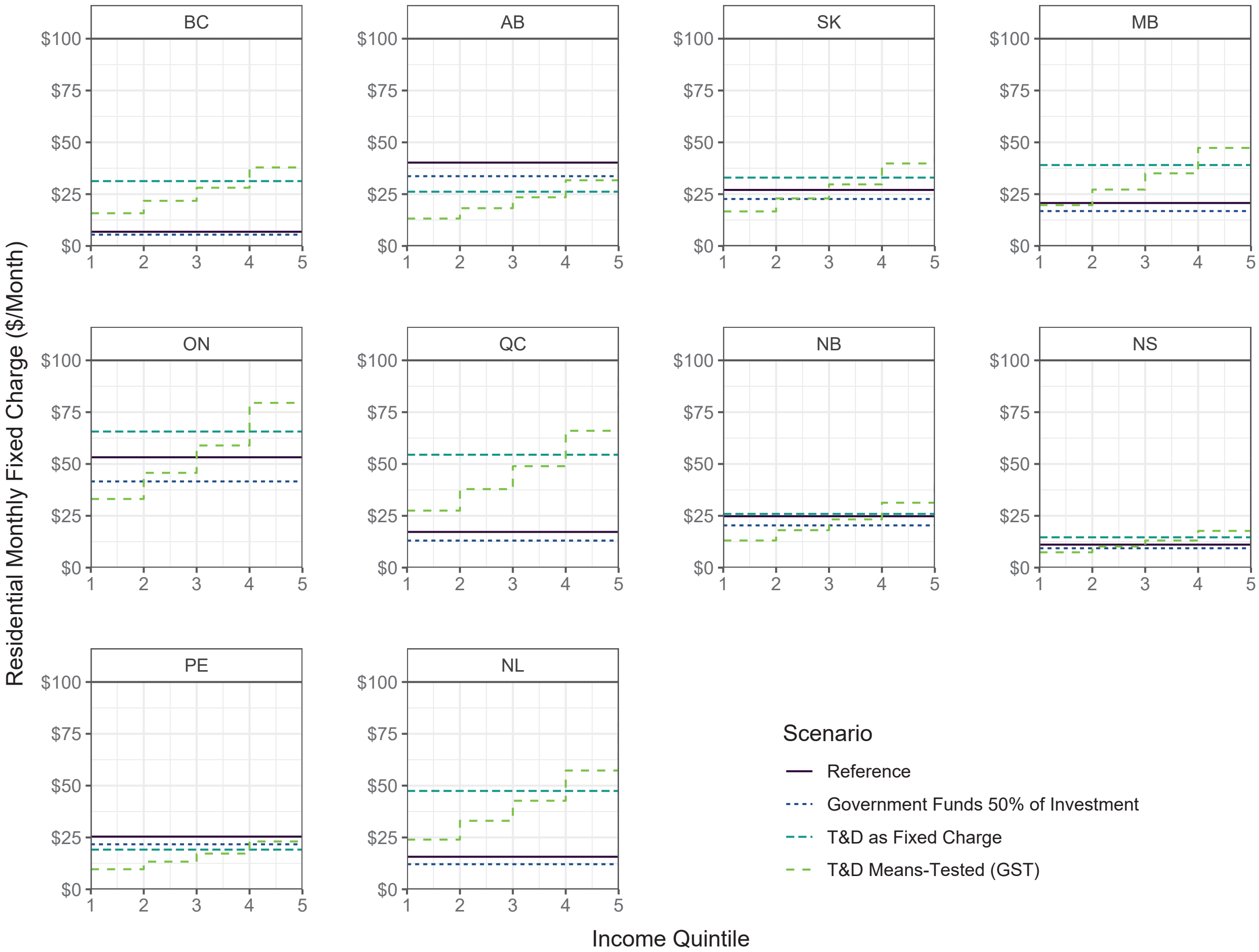


Note: Presents average residential volumetric electricity rates between 2020 and 2050 in each province. The figure is not representative of total household costs, as fixed charges are omitted (see Figure 20), and the figure does not account for changes in use. The reference case is status quo rate-design systems in each province, with uniform scaled cost increases across the income distribution. The "Government Funds 50 per cent of Investment" scenario assumes government funds 50 per cent of new investment in generation, transmission, distribution, and storage costs within a province. The "Transmission and distribution as fixed charge" scenario removes some system costs from volumetric rates and creates a fixed monthly charge based on the cost of transmission and distribution; residential volumetric electricity rates are determined by the remaining costs based on the current rate structure (fixed operations and maintenance, variable operation and maintenance, fuel, existing debt, and amortized capital cost of investments in generation and storage).

Figure 20 shows different fixed-cost scenarios in 2030 by province and income quintile. (Fixed costs are increasing over time but the patterns remain the same.) The difference in fixed charges is stark for hydro provinces—British Columbia, Manitoba, Quebec, and Newfoundland and Labrador—with a reference-scenario fixed charge close to when government funds 50 per cent of investment. There is a clear difference in rate designs across provinces.[17] For example, British Columbia and Quebec currently absorb the majority of fixed systems costs into variable rates, and so the reference case fixed costs are quite low compared to when transmission and distribution costs are a fixed charge. This is reflected in the relatively higher volumetric charge for these provinces shown in Figure 18. Also notable in Figure 20 is the difference between large and smaller thermal provinces. New Brunswick, Nova Scotia, and Prince Edward Island all have relatively similar fixed charges across the scenarios, compared to Ontario, Alberta, and Saskatchewan with a greater distribution.

Figure 20

2030 monthly fixed charges under different rate-design and system-funding scenarios



Note: Presents households' monthly fixed charges in 2030 in each province. The figure is not representative of total household electricity expenditures, as volumetric rates are omitted (see Figure 19). The reference case is status quo rate-design systems in each province, with uniform scaled cost increases across the income distribution. The "Government Funds 50 per cent of Investment" scenario assumes government funds 50 per cent of new investment in generation, transmission, distribution, and storage costs within a province. The "T&D as Fixed Charge" scenarios remove some system costs from volumetric rates and creates a fixed monthly charge based on the cost of transmission and distribution. Residential volumetric electricity rates are determined by the remaining costs based on the current rate structure (fixed operations and maintenance, variable operation and maintenance, fuel, existing debt, and amortized capital cost of investments in generation and storage).

[17] See Bishop, Ragab, and Shaffer (2020) for a discussion of different provincial rate-design systems.

CONCLUSION

Aligning electricity systems with Canada's net zero commitments could increase electricity rates in some provinces, and increased electrification will increase households' electricity use. The combination could increase households' overall electricity expenditure. However, these changes correspond with decreased use of and spending on gasoline, natural gas, and other fossil fuels. While spending on electricity will likely increase, total energy spending will decline (Dion et al. 2022).

Complicating this *big switch* from fossil fuels to low- or no-emissions electricity, however, is the fact that electricity costs are currently borne regressively: lower-income households spend a higher proportion of their incomes and total expenditure on electricity compared to higher-income households. This regressivity could be exacerbated under the net zero transition, particularly if lower-income households experience slow or stagnant income growth. For this reason, policymakers concerned about distributional fairness should consider measures like we analyse above to protect lower-income households and ensure electricity costs from Canada's net zero transition are borne fairly.

Importantly, the types of rate design that improve incentives for electrification—apportionment of electricity system costs into volumetric rates and fixed charges, with volumetric rates closer to marginal costs of electricity—also risk exacerbating regressivity. This is due to fixed charges being uniform, placing a disproportionate burden on lower-income households that typically consume less electricity.

Addressing cost regressivity on the path to net zero can take many forms; we present two options that governments can use alone or in combination. The first is adjusting fixed charges to be income-tested. This approach addresses the concerns around equity in fixed charges, but only moves costs around within the ratepayer base. A second approach is for governments to assume some or all of these system costs. Federal and provincial income tax systems are progressive, meaning that higher incomes are taxed at a higher rate. Government funding for electricity system investments addresses regressivity by reducing electricity users' exposure to total electricity system cost increases, and instead paying for a portion of Canada's climate commitments using the progressive tax system. This mitigates increases to both fixed charges and volumetric rates in the electricity sector. When such system funding is federal rather

than provincial, it also adjusts for the unequal investment burdens that different regions face (which is largely a function of the relative availability of hydro versus fossil fuel resources).

Both approaches are tools that can help address regressivity and electricity affordability, and they do so in different ways. Changing fixed charges can be implemented by regulators independently, or by provincial or territorial governments via policy intervention. Government funding of system investments is solely the purview of federal, provincial, and territorial governments. Applying these tools in combination is a viable option for policymakers interested in multiple levers to address equity and efficiency goals in the net zero transition.

Acknowledgments

We thank Christopher Roney, Electric Power Research Institute; Ganesh Doluweera, the Canada Energy Regulator (CER); John Bistline, Electric Power Research Institute (EPRI); Kathleen Vaillancourt, ESMIA Consultants; Brienne Riehl, Navius Research; and Ryan Ness, Canadian Climate Institute, for their input into our analysis. We thank EPRI, CER, and ESMIA for sharing their modelling data, which makes this work possible.

This analysis uses Statistics Canada's Social Policy Simulation Database and Model version 29.0. The assumptions and calculations underlying the simulation results were prepared by the authors and the responsibility for the use and interpretation of these data is entirely theirs.

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APPENDIX I: METHODS

Estimating household electricity use

We estimate household electricity use with SPSD/M synthetic microdata. The SPSD is a detailed representative database of Canadian individuals including their economic and family characteristics, expenditure by commodity type, and tax and transfer information. The model part of SPSD/M allows for counterfactual analysis of tax and transfer policy. SPSD/M version 29.0 uses 2017 Survey of Household Spending data as a base for the expenditure data.

We compile 2017 electricity prices (volumetric rates and fixed charges) for each province and sub-provincial region in Canada (see Table 1 in Appendix II). We then divide annual household electricity expenditure (exclusive of taxes) by the electricity price, adjusting for fixed monthly charges, provincial subsidies, and two-tiered rate systems. This gives us imputed electricity use:

$$\mathrm{use}_{\mathrm{hp}} = \frac{\mathrm{exp}_{\mathrm{hp}} - f_{\mathrm{p}}}{\mathrm{c}_{\mathrm{p}}}$$

where h denotes household and p denotes province, f denotes fixed monthly charges, and c is the cost (price) of electricity faced by residential consumers.

We use this imputed electricity use to re-estimate current electricity expenditures using 2021 electricity volumetric rates and fixed charges (2021 prices multiplied by imputed electricity use, plus 2021 fixed charges); see Table 2 in Appendix II for the values we use. To calculate a gross average cost of electricity (per kWh) paid by households in each province, we sum the households' electricity expenditure in each province to construct aggregate household expenditure, and divide aggregate expenditure by aggregate use, where aggregate use is the sum of household electricity use in each province. This gross average cost folds in the fixed charges, which vary by province, to make the values comparable across provinces. We refer to this as the *average household electricity cost*.

Calculating utility cost pressure

The Canadian Climate Institute provided us with the modelling results from three modelling teams: EPRI, ESMIA (Institut de l'énergie Trottier), and CER (Canada Energy Regulator). These teams provided results from simulations of the Canadian electricity between 2020 and 2050 (and beyond). Modelling results include electricity demand growth; installed electricity capacity in megawatts (MW); generation shares in gigawatt-hours (GWh); capital investment costs for investments in generation, distribution, transmission, and storage; fixed and variable operations and maintenance (O&M) costs; fuel use; and carbon pricing charges. We do not include investment costs for making electricity systems more resilient to climate change. We worked with the modelling teams to ensure compatibility between the cost estimates. As the CER and ESMIA models do not include intra-provincial transmission and distribution investment, we add intra-provincial distribution and transmission costs from EPRI to both the CER and ESMIA cost results to ensure comparability.

All three models forecast system investments and do not include the value of existing debt from past investments. As existing debt is amortized and included in households' electricity rates (both volumetric rates and fixed charges), any cost estimates from these models will understate potential costs to households. To better reflect the financial situation of utilities across Canada, we compile data on long-term debt held by the utilities. Not knowing the exact debt schedule of long-term debt held by utilities across Canada, we amortize this long-term debt over 30 years at an interest rate of six per cent, and divide by model-specific future provincial generation estimates to calculate an expected debt payment per megawatt-hour (MWh) for each province. Similarly, we amortize all capital investments in new generation, transmission, distribution, and storage over 25 years at an interest rate of six per cent.

For 2020 (or the closest available year), 2030, 2040, and 2050 we calculate the modelled average cost of generation in each province for each model (including our modifications to ensure comparability). The average cost of generation is total system costs (including amortized debt and new capital investments) divided by modelled generation.

We calculate each province's electricity markup for residential ratepayers with the difference between average household electricity cost and the average cost of generation. This mark-up can result from a range of factors including return on equity, administrative costs, higher distribution costs for residential customers, and other costs for which we don't have modelling data. We make the simplifying assumption that the markup is time-invarying and province-specific.

$$\text{Gross average cost}_{\text{p2020}} - \text{Modelled average cost}_{\text{Mp2020}} = \text{Markup}_{\text{Mp}}$$

where, p refers to province, and M refers to model (CER, EPRI, ESMIA, or the mean of the three).

To calculate residential rates in future years, we add the time-invarying, provincial markup to average cost estimates calculated using the modelling results for the years 2030, 2040, and 2050.

$$\text{Residential rate}_{\text{Mpt}} = \text{Modelled average cost}_{\text{Mpt}} + \text{Markup}_{\text{Mp}}$$

Calculating future electricity demand

The three models forecast residential electricity demand and population change for each province or region, in 10-year increments between 2020 and 2050 (ESMIA forecasts to 2060). We use these data to calculate per capita electricity demand in current and future years. We compare these per capita electricity consumption estimates to Natural Resources Canada's Comprehensive Energy Use Database and our imputed energy use from SPSD/M synthetic microdata. The match is quite good for most provinces, giving us confidence in our own per capita electricity estimates, and those of the models. We assume that the composition of households will not change significantly between now and 2050, and so assume that the growth of household electricity consumption will closely match the growth of per capita electricity in each province.

Estimating future household electricity costs

We estimate future household electricity costs using results from all three models and the mean of the three models.

We assume that households at all income levels within a province will increase their electricity use at the same growth rate. That is, growth rates are province- and time-invariable. We normalize provincial electricity consumption estimates at unity with 2020 as our base year. We then scale electricity use for each household by this province- model- and time-specific electricity growth factor.

$$\text{Electricity use}_{\text{hpMt}} = \text{Imputed electricity use}_{\text{hp2020}} * \text{Normalized growth factor}_{\text{pMt}}$$

where *h* refers to household h in the SPSD/M synthetic microdata, p refers to province, M refers to model (CER, EPRI, ESMIA, or the mean of the three), and t refers to year (2020, 2030, 2040, and 2050).

We then create a scaling factor for residential average costs, normalized with 2021 residential average costs equal to 1.0.

$$\frac{\text{Estimated residential average cost}_{\text{pMt}}}{\text{Current residential average}_{\text{p2021}}} = \text{Normalized residential rate pressure}_{\text{pMt}}$$

We multiply the normalized electricity use growth factor and the normalized residential rate pressure factor to create an overall scaling factor:

$$\text{Scaling}_{\text{pMt}} = \text{Normalized residential rate pressure}_{\text{pMt}} * \text{Normalized growth factor}_{\text{pMt}}$$

We then multiply household cost in 2021 (previously calculated using 2021 electricity rates and imputed electricity 2017 use) by the scaling factor to estimate future household electricity cost from volumetric rates.

$$\text{Household cost}_{\text{hpMt}} = \text{Scaling}_{\text{pMt}} * \text{Imputed electricity use}_{\text{hp2020}}$$

We can then calculate mean household cost by income quintile in each province to compare the effect of future electricity scenarios.

Rate design and payment structure simulations

We modify rate designs to understand how different variations would affect electricity affordability for low-income households. Energy, and specifically electricity affordability, is of increasing interest in policy circles. There are two issues of concern here related to system design and increased costs and the ability of lower-income households to bear these costs. Electricity bills do not always distinguish between purely marginal costs of production and the overall system costs, folding in fixed capital costs into volumetric rates. Some systems do distinguish between fixed costs and set volumetric rates close to marginal costs. However, uniform increases in either case will fall disproportionately on lower-income households with less disposable income to absorb cost increases. Moreover, lower-income households may have limited ability to adapt to energy system changes, putting them at increased risk of a heat-or-eat dilemma. As electricity rate design is a policy choice, analysis of design alternatives and these alternatives' distributional consequences is an important part of evaluating the consequences of net zero electricity investments.

We examine five different design variations. First, setting monthly fixed charges equal to estimated transmission and distribution costs for the household. This is often proposed as a way to better reflect the cost structure of delivering electricity to households. Households must be served with a fixed connection regardless of electricity use. Often, utilities pay for some of the residential transmission and distribution costs using revenues from the volumetric rates (cents/kWh). Separating the variable costs of generation from the fixed cost of service is a way to present a more efficient price signal.[18] Increasing fixed costs is also suggested as a way to avoid cross-subsidizing rooftop solar photovoltaics (PV). When solar producers are paid at the retail rate of electricity, and that retail rate includes fixed components like transmission and distribution and the generation capacity that must be available at peak times, solar is over-compensated and non-solar customers cross-subsidize residential solar producers (Dolter and Boucher 2018). If solar deployment is high enough, this means electricity rates must increase to compensate for the revenues lost to self-generation of solar. However, increasing fixed rates is also highly regressive, impacting low-income households that on average use less electricity. Conversely, increasing fixed charges allows volumetric rates to be lowered, and this is desirable to encourage electrification of vehicles, buildings, business, and industry (Borenstein, Fowlie, and Sallee 2021).

To avoid negatively impacting low-income households, fixed charges can be means-tested, varying with income. They can be made as progressive as a sales tax (in Canada, the GST or HST) or income tax (Borenstein and Bushnell 2021; Borenstein, Fowlie, and Sallee 2021). We model both options by first calculating the proportion of GST and income tax paid, respectively, by each income quintile in Canada, and then designing uniform within-quintile fixed charges that match those proportions. These simulations form our second and third scenarios.

Achieving climate goals by pursuing a zero-emissions electricity grid is an activity that is initiated by government and consequently could be funded by government (Borenstein, Fowlie, and Sallee 2021). We model government funding 50 per cent of required new investments in each province. Here, we only model government funding 50 per cent of the residential portion of new system investments. In all government-funding scenarios, the remaining electricity system costs in each province are modelled as in our reference case, using existing provincial rate systems. The choice of 50 per cent government funding is arbitrary and meant to illustrate the interprovincial and inter-household consequences of government funding of net zero investments.

We model two separate government funding scenarios. First, we model a scenario where the federal government pays 50 per cent of required new investments in all provinces, and funds this with increases to federal personal income taxes. Second, we model a scenario where each provincial government funds the 50 per cent of new investments with increases in provincial personal income taxes. We model the two scenarios using the tax simulation capabilities of SPSD/M.

[18] This is particularly relevant in the case of small-scale rooftop solar or electric technology investments.

APPENDIX II: SUPPLEMENTARY TABLES

Table 1

Provincial electricity rates for imputing electricity use (2017 dollars)

Prov	Location	Annual fixed charge ($)	Volumetric charge, cents per kWh (Tier 1)	Volumetric charge, cents per kWh (Tier 2)
BC	Rural	73.91	0.10280	0.1767
	Population under 30,000	69.31	0.08580	0.1287
	Population 30,000 to 99,999	69.31	0.08580	0.1287
	Population 100,000 to 499,999	69.31	0.08580	0.1287
	Vancouver	69.31	0.08580	0.1287
AB	Rural	293.48	0.06060	
	Population under 30,000	293.48	0.06060	
	Population 30,000 to 499,999	293.48	0.06060	
	Edmonton	293.48	0.06060	
	Calgary	257.64	0.06060	
SK	Rural	381.24	0.13741	
	Population under 100,000	264.12	0.13741	
	Saskatoon	300.84	0.15650	
	Regina	264.12	0.13741	
MB	Rural	193.92	0.08200	
	Population under 100,000 and Brandon	96.96	0.08200	
	Winnipeg	193.92	0.08200	
ON	Rural	1953.72	0.09450	
	Population under 30,000	1953.72	0.09450	
	Population 30,000 to 99,999	828.98	0.09450	
	Population 100,000 to 499,999	612.12	0.09450	
	Ottawa	208.92	0.09450	
	Hamilton and Burlington	275.16	0.09450	
	Toronto	342.72	0.09450	
QC	Rural	148.34	0.05710	0.0868
	Population under 30,000	148.34	0.05710	0.0868
	Population 30,000 to 99,999	148.34	0.05710	0.0868
	Population 100,000 to 499,999	148.34	0.05710	0.0868
	Quebec City	148.34	0.05710	0.0868
	Montreal	148.34	0.05710	0.0868

Prov	Location	Annual fixed charge ($)	Volumetric charge, cents per kWh (Tier 1)	Volumetric charge, cents per kWh (Tier 2)
NB	Rural	284.4	0.10840	
	Population under 30,000	259.44	0.10590	
	Population 30,000 to 99,999 and Fredericton	259.44	0.10590	
	Saint John and Moncton	259.44	0.10590	
NS	Rural	129.96	0.14646	
	Population under 100,000	129.96	0.14646	
	Halifax	129.96	0.14646	
	Cape Breton	129.96	0.14646	
PEI	Rural and population under 30,000	309.48	0.13890	0.1103
	Charlottetown	309.48	0.13890	0.1103
NL	Rural	254.28	0.10900	
	Population under 100,000	194.28	0.10900	
	St John's	194.28	0.10900	

Table 2

Reference case electricity rates (2021 dollars)

Province	Annual fixed charge ($)	Volumetric charge, cents per kWh (Tier 1)	Volumetric charge, cents per kWh (Tier 2)
BC	75.81	0.0939	0.1408
Alberta	478.08	0.0743	
Saskatchewan	273.48	0.14228	
Manitoba	212.64	0.08983	
Ontario	462.36	0.1221	
Quebec	150.26	0.06159	0.09502
New Brunswick	273.84	0.1138	
Nova Scotia	129.96	0.16008	
PEI	309.91	0.1437	0.1142
Newfoundland and Labrador	192	0.1252	

Table 3

Federal personal income tax rate changes

2021 tax rate	2030 simulation	2040 simulation	2050 simulation	Tax bracket
15.0%	15.48%	15.67%	15.83%	On the first $49,020 of taxable income
20.5%	20.98%	21.17%	21.33%	On the portion of taxable income over $49,020 up to $98,040
26.0%	26.48%	26.67%	26.83%	On the portion of taxable income over $98,040 up to $151,978
29.0%	29.48%	29.67%	29.83%	On the portion of taxable income over $151,978 up to $216,511
33.0%	33.48%	33.67%	33.83%	On taxable income over $216,511

Table 4

British Columbia personal income tax rate changes

2021 tax rate	2050 simulation	Tax bracket
5.06%	5.56%	On the first $42,184 of taxable income
7.7%	8.20%	On the portion of taxable income over $42,184 up to $84,369
10.5%	11.00%	On the portion of taxable income over $84,369 up to $96,866
12.29%	12.79%	On the portion of taxable income over $96,866 up to $117,623
14.7%	15.20%	On the portion of taxable income over $117,623 up to $159,483
16.8%	17.30%	On the portion of taxable income over $159,483 up to $222,420
20.5%	21.00%	On the portion of taxable income over $222,420

Table 5

Alberta personal income tax rate changes

2021 tax rate	2050 simulation	Tax bracket
10%	10.83%	On the first $131,220 of taxable income
12%	12.83%	On the portion of taxable income over $131,220 up to $157,464
13%	13.83%	On the portion of taxable income over $157,464 up to $209,952
14%	14.83%	On the portion of taxable income over $209,952 up to $314,928
15%	15.83%	On the portion of taxable income over $314,928

Table 6

Saskatchewan personal income tax rate changes

2021 tax rate	2050 simulation	Tax bracket
10.5%	11.31%	On the first $45,677 of taxable income
12.5%	13.31%	On the portion of taxable income over $45,677 up to $130,506
14.5%	15.31%	On the portion of taxable income over $130,506

Table 7

Manitoba personal income tax rate changes

2021 tax rate	2050 simulation	Tax bracket
10.8%	11.35%	On the first $33,723 of taxable income
12.75%	13.30%	On the portion of taxable income over $33,723 up to $72,885
17.4%	17.95%	On the portion of taxable income over $72,885

Table 8

Ontario personal income tax rate changes

2021 tax rate	2050 simulation	Tax bracket
5.05%	5.994%	On the first $45,142 of taxable income
9.15%	10.094%	On the portion of taxable income over $45,142 up to $90,287
11.16%	12.104%	On the portion of taxable income over $90,287 up to $150,000
12.16%	12.16%	On the portion of taxable income over $150,000 up to $220,000
13.16%	13.16%	On the portion of taxable income over $220,000

Table 9

Quebec personal income tax rate changes

2021 tax rate	2050 simulation	Tax bracket
15%	15.7%	On the first $45,105 of taxable income
20%	20.7%	On the portion of taxable income over $45,105 up to $90,200
24%	24.7%	On the portion of taxable income over $90,200 up to $109,755
25.75%	26.5%	On the portion of taxable income over $109,755

Table 10

New Brunswick personal income tax rate changes

2021 tax rate	2050 simulation	Tax bracket
9.40%	10.20%	On the first $43,835 of taxable income
14.82%	15.62%	On the portion of taxable income over $43,835 up to $87,671
16.52%	17.32%	On the portion of taxable income over $87,671 up to $142,534
17.84%	18.64%	On the portion of taxable income over $142,534 up to $162,383
20.30%	21.10%	On the portion of taxable income over $162,383

Table 11

Nova Scotia personal income tax rate changes

2021 tax rate	2050 simulation	Tax bracket
8.79%	9.32%	On the first $29,590 of taxable income
14.95%	15.48%	On the portion of taxable income over $29,590 up to $59,180
16.67%	17.20%	On the portion of taxable income over $59,180 up to $93,000
17.5%	18.03%	On the portion of taxable income over $93,000 up to $150,000
21%	21.53%	On the portion of taxable income over $150,000

Table 12

Prince Edward Island personal income tax rate changes

2021 tax rate	2050 simulation	Tax bracket
9.8%	10.59%	On the first $31,984 of taxable income
13.8%	14.59%	On the portion of taxable income over $31,984 up to $63,969
16.7%	17.49%	On the portion of taxable income over $63,969

Table 13

Newfoundland personal income tax rate changes

2021 tax rate	2050 simulation	Tax bracket
8.7%	9.23%	On the first $38,081 of taxable income
14.5%	15.03%	On the portion of taxable income over $38,081 up to $76,161
15.8%	16.33%	On the portion of taxable income over $76,161 up to $135,973
17.3%	17.83%	On the portion of taxable income over $135,973 up to $190,363
18.3%	18.83%	On taxable income over $190,363