A MACDONALD-LAURIER INSTITUTE PUBLICATION

Edgardo Sepulveda

CHASING THE WIND

The value of wind generation in a low-emission nuclear and hydro-dominant grid: the case of Ontario

September 2024

TRUE NORTH IN CANADIAN PUBLIC POLICY

TRUE NORTH IN CANADIAN PUBLIC POLICY

Contents

The author gratefully acknowledges the support of Daniel Teeter who assisted with statistical coding and implementation. The author also acknowledges Tom Hess, Scott Luft, Chris Adlam and an anonymous peer-reviewer for their helpful comments on earlier draft versions of this report. At the Macdonald-Laurier Institute, the author thanks Heather Exner-Pirot for agreeing to publish this report and Mark Reid for his editorial assistance.

Cover design: Renée Depocas (photo: Anna Jimenez)

Executive summary | *sommaire*

In 2018, the newly elected Ontario government passed one of its first pieces of legislation – to repeal the *Green Energy Act* (GEA).

Modelled on German legislation to promote wind and solar generation, the 2009 GEA initiated the largest use of guaranteed above-market price long-term contracts (FITs) in North America.

What caused Ontario Premier Doug Ford to pull the plug?

The GEA proved to be incredibly contentious locally and province-wide: it gave government the power to override local opposition to the installation of wind turbines and contributed to an unprecedented increase in electricity prices. Hoping to jump-start wind generation, Premier Dalton McGuinty's government established high wind prices, fixed for 20 years, which averaged $151/MWh over the 2020–23 period.

As the sector grew, so did the fiscal liability of those contracts. Multi-billion-dollar government subsidies started in 2017 and will total $7.3 billion for the current fiscal year (Ontario 2024a), equivalent to 0.65 percent of provincial GDP (Ontario 2024b). No other government in Canada has subsidized its electricity sector by this much for so long. Unsurprisingly, the very German government that first introduced FITs is likewise under fiscal pressure due to ballooning subsidies (Sorge 2024).

This paper tells the economic story of wind generation in Ontario in several parts. First, we provide an overview of wind generation's impact on electricity costs, prices and subsidies: to keep prices low, Ontario subsidizes 70 percent of the cost of wind. Second, based on regression and cost-benefit analysis, we show that the costs of wind far exceed its societal and climate benefits for the 2020–23 period, with average net cost of -$124/MWh, due to financial (high prices) and structural factors. Due to its nuclear and hydro-dominant generation and elimination of coal, Ontario is one of the lowest-emission large grids in the world. The climate benefit from any new zero-emission generation will be limited to the extent it can displace gas generation. Relative to other areas, Ontario's wind capacity factors are modest and out of sync with gas generation, all resulting in a relatively low wind emissions offset (0.227 tCO_2/MWh). Third, we calculate a cost-benefit "break-even" wind price of $46/MWh for the 2027–2030 period.

There are financial and structural challenges to aligning the public costs and benefits of wind generation in Ontario. Given the political defeat of the GEA, the province should have strong incentive not to "overpay" for wind within Ontario's single-buyer system.

For legacy wind projects whose contracts will expire, we explore the benefits of the province implementing a wind re-contracting standard offer of $46/MWh for a maximum ten-year contract. Some wind operations would shut down, while others would recontract on those terms.

Among a broader set of options for new wind projects, one would be to continue with the private wind IPP contracts approach, but for the Independent Electricity System Operator (IESO) to design a competitive auction process with a maximum reserve price of $46/MWh. Another possibility would be to discard the contractual approach in favour of financing and compensating wind projects based on cost-of-service economic regulation. A third option would be to leverage the larger economies of scale and lower cost of public financing and have new wind projects publicly owned and operated, as is the case for about half the wind capacity in PEI and the thrust of the new strategy in Quebec. **MLI**

***En 2018, le gouvernement nouvellement élu** de l'Ontario adoptait un de ses premiers textes législatifs, abrogeant la* Loi de 2009 sur l'énergie verte.

La loi de 2009, élaborée sur le modèle de la loi allemande visant à promouvoir la production d'énergie éolienne et solaire, avait enclenché la plus grande utilisation en Amérique du Nord des contrats à long terme de tarifs de rachat garantis (TRG) supérieurs au prix courant.

Pour quelle raison le premier ministre de l'Ontario, Doug Ford, a-t-il décidé de « débrancher » ?

Les TRG ont suscité une vive polémique à l'échelle locale et provinciale : ils permettaient au gouvernement de faire fi de l'opposition locale à l'installation d'éoliennes et ont entraîné une hausse sans précédent des prix de l'électricité. Le gouvernement du premier ministre Dalton McGuinty avait fixé des tarifs élevés pour 20 ans dans le but de relancer la production éolienne : ils ont atteint en moyenne 151 $/MWh pendant la période 2020-23.

Le secteur a pris de l'expansion, mais la charge fiscale imposée par ces contrats en a fait tout autant. Les subsides ont coûté plusieurs milliards de dollars en 2017 et totaliseront 7,3 milliards de dollars pour l'exercice fiscal en cours (Ontario 2024a), ce qui équivaut à 0,65 % du PIB provincial (Ontario 2024b). Aucun autre gouvernement au Canada n'a apporté une aide aussi massive et aussi longue à son secteur de l'électricité. Évidemment, l'État allemand, celui-là même qui a été le premier à mettre en place les TRG, est également confronté à une pression fiscale croissante en raison de l'explosion des subsides (Sorge 2024).

Ce document aborde, dans ses diverses parties, l'histoire économique de la production d'énergie éolienne en Ontario. Dans un premier temps, nous examinons l'effet de cette production sur les coûts, les prix et les subsides accordés à l'électricité : afin de maintenir les prix bas, l'Ontario subventionne actuellement 70 % du coût de l'énergie éolienne. Ensuite, en utilisant une technique de régression et une analyse coûts-avantages, nous démontrons que les coûts nets moyens de l'éolien dépassent largement ses bénéfices sociétaux et climatiques pour la période 2020-2023 – soit 124 $/MWh – en raison des facteurs financiers (prix élevés) et structurels qui y sont rattachés. Comme la production ontarienne est dominée par le nucléaire et l'hydroélectricité et que le charbon est désormais exclu, la province dispose de l'un des grands réseaux les moins polluants au monde. Toutefois, l'impact positif sur le climat de toute nouvelle production d'électricité sans émissions sera conditionné par les limites de sa capacité à remplacer la production d'électricité au gaz. En Ontario, les coefficients de capacité pour l'éolien sont, par rapport à d'autres régions, ténus et en décalage total avec le gaz, de sorte que les émissions éoliennes (0,227 tCO_2/MWh) sont relativement peu compensatoires. Enfin, nous fixons un tarif pour l'énergie éolienne qui correspond au seuil de rentabilité de 46 $/MWh pour la période 2027-2030.

Il y a des difficultés financières et structurelles à concilier les coûts et les bénéfices publics liés à la production d'énergie éolienne en Ontario. Étant donné l'échec politique de la loi sur l'énergie verte, il est essentiel que la province soit fortement encouragée à ne pas « surpayer » l'énergie éolienne dans le cadre du système d'acheteur unique de l'Ontario.

En ce qui concerne les projets éoliens patrimoniaux en fin de contrat, nous examinons les bénéfices de la mise en place par la province d'une offre standard de renouvellement à 46 $/MWh pour une durée maximale de dix ans. Certains projets éoliens seraient terminés, tandis que d'autres seraient renouvelés à ces conditions.

Parmi un éventail plus large de choix pour l'éolien, il y aurait la poursuite de l'approche axée sur les projets portés par des producteurs indépendants, mais en demandant à SIERE (Société indépendante d'exploitation du réseau d'électricité) de mettre en place un processus d'enchères concurrentielles prévoyant un prix de réserve maximal de 46 $/MWh. Une autre option consisterait à abandonner l'approche contractuelle de financement et d'indemnisation des projets éoliens pour adopter une réglementation économique fondée sur le coût du service. Une troisième possibilité serait de profiter des économies d'échelle plus importantes et du coût plus bas du financement public et de faire en sorte que les nouveaux projets soient détenus et exploités par l'État, comme c'est le cas pour environ la moitié de la capacité éolienne de l'Île-du-Prince-Édouard et pour l'idée maîtresse de la nouvelle stratégie au Québec. MLI

Introduction

In this paper we provide a cost-benefit assessment of wind generation in Ontario for the 2020–23 period and on a forward-looking basis for the 2027–2030 period. Our work is based on well-established economics literature examining the interaction of wind in various grids and its corresponding cost-benefit from several perspectives. This includes work on the Texas electricity grid (Cullen 2013, Novan 2015), as well as more recent work analyzing the Ontario grid (Bahramian et al. 2021) and several regions of the United States (Fell and Johnson 2021).

This literature suggests that the social and climate cost-benefit of wind generation will be grid-specific. The lower the price of wind on the grid and the more that wind displaces higher-emitting generation, the higher wind's social and climate benefit. And vice versa. We find a large negative net cost of wind for 2020–23 reflecting Ontario's relatively high wind prices and low wind emissions offset.

The rest of this report is structured as follows.

- **Chapter 2** provides the policy and structural context for Ontario's wind roll out. We first summarize Ontario's distinctive sector policy and how wind generation fits into that framework, including how its relatively high average price of $151/MWh in the 2020–23 period impacted system costs and government subsidies. We then review some of the factors that are likely to impact the size of the net climate benefits of wind, including how it interacts with the existing generation mix and emissions intensity, and the nature of Ontario's "wind profile," including average and seasonal capacity factors and correlation with emitting generation.

- **Chapter 3** presents the results of our regression analysis of the interaction of wind generation with other generation technologies. We apply the regression results to a cost-benefit analysis of wind generation and find that the costs far exceeded the benefits for the 2020–23 period, with average net cost of -$124/MWh. We also undertake a forward-looking cost-benefit analysis for the 2027–2030 period based on a new LCOE-based reference wind price of $80/MWh and calculate an average net cost of wind of -$38/MWh. The cost-benefit "break-even" wind price for 2027–2030 is $46/MWh.
- Based on the results of the cost-benefit analysis and policy discussion, **Chapter 4** concludes the report.
- The data and methodology **Appendix** provides more detailed and technical background to the analysis presented in this report.

Wind in Ontario's electricity sector

As background to the formal analysis presented in Chapter 3, this chapter provides the policy and structural context for Ontario's wind roll out. We first summarize Ontario's distinctive sector policy and how wind generation fits into that framework. This is critical to understanding the financial aspects of the cost-benefit analysis presented in Chapter 3. We then review several non-financial factors that are likely to impact the size of the net climate benefits of wind, including how it interacts with the existing generation mix and emissions intensity, and the nature of Ontario's "wind profile," including its average and seasonal capacity factors.

Ontario's distinctive sector policy

Ontario's installed wind capacity of 5.5 GW (IESO 2024c) has largely evolved within an electricity sector that is unique in North America: a restructured, single-buyer with a system-wide contracts-for-difference (CfD) mechanism, majority out-of-market revenues, and high subsidization. To appreciate the scope of options that we discuss in Chapter 3, it is first important to understand this distinctive hybrid approach.

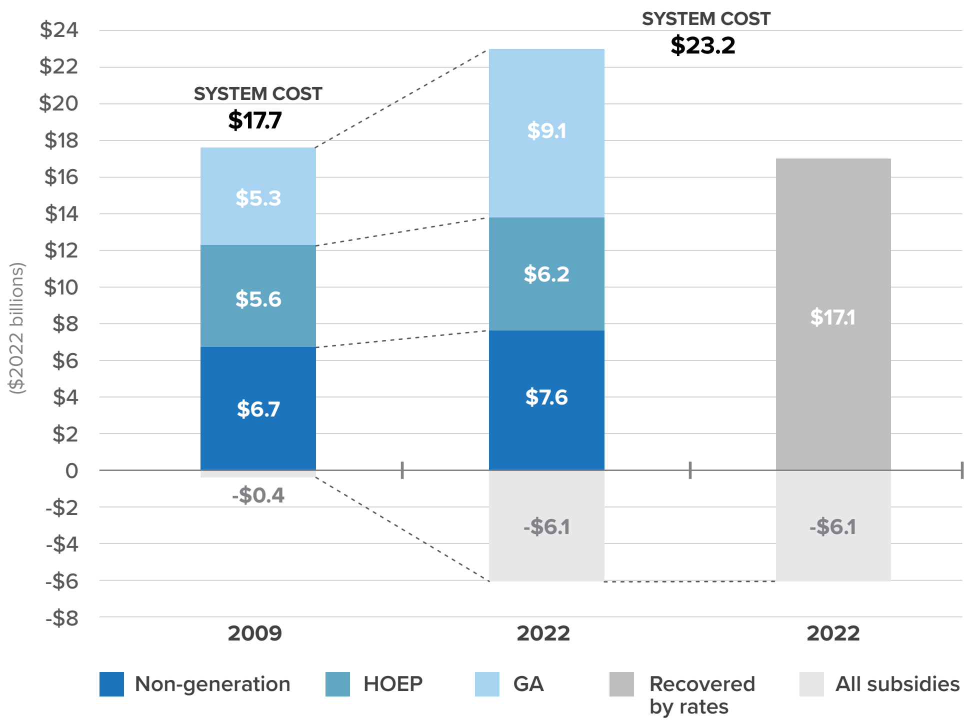
Ontario was one of two provinces (Alberta being the other) whose government decided to "restructure" (also referred to as "unbundling") the sector by requiring that the generation segment be unbundled from transmission and distribution, with the objective of facilitating competition in generation. Prior to restructuring, Ontario had a vertically integrated sector with the provincially owned Ontario Hydro (OH) possessing most generation assets, virtually all transmission resources and some rural distribution resources, and providing electricity to municipally owned local distribution companies (LDCs). In preparation for market opening in May 2002, OH was split into several entities, including Ontario Power Generation (OPG), the generation-only entity, Hydro One (H1) holding the transmission and rural distribution assets and the (current) Independent Electricity System Operator (IESO) responsible for operating the electricity market.

Wholesale generation prices spiked in the summer following market opening, and as designed, so did retail electricity prices. Facing a public backlash and an upcoming election, the government lowered and then froze retail prices by December 2002 (CBC 2002). Those months from May to November 2002 would be the only period during which the competitive restructured market functioned as originally designed in Ontario (Trebilcock and Harb 2005).

In 2005, the new government established the single-buyer model for generation in Ontario by creating the Ontario Power Authority (OPA) responsible for contracting existing and new generation that was not otherwise economically regulated by the Ontario Energy Board (OEB). Indeed, virtually all wind resources in Ontario have been centrally procured by the government.

To tie the administrative OPA element to the competitive IESO element, the government introduced a sector-wide contracts-for-difference mechanism in 2005. Generating entities would receive market revenues based on the hourly Ontario energy price (HOEP), on top of which they would receive out-of-market CfD payments equal to the difference between their individual "strike price" (set by regulation or contracts) and the HOEP. Those CfD-type payments are funded via the Global Adjustment (GA) mechanism, which has generally been fully recovered via rates. One consequence of the single-

FIGURE 1: Ontario system costs: Non-generation, HOEP, GA and subsidies



Sources: MSP (2023), OEB (2023 and previous), Statistics Canada (2024), and author's calculations

buyer CfD approach policy is that there has been virtually no "merchant" uncontracted HOEP-only entry into Ontario, a feature that we further discuss in Chapter 3.

Figure 1 compares the 2009 and 2022 generation-related (HOEP and GA) and non-generation (transmission, distribution, other market and conservation) costs, and government programs to reduce retail prices ("subsidies") in constant dollar terms. It shows that system costs excluding subsidies increased by $5.42 billion, from $17.73 to $23.15 billion, a 30 percent increase. This increase was mostly driven by generation costs, which rose by $4.5 billion. Within the generation element, Figure 1 shows that in 2022 generation resources received 60 percent from the GA ($9.1 billion), or a majority out-of-market revenues, and 40 percent from the HOEP market ($6.2 billion).

Like many other jurisdictions, Ontario has in the past directly or indirectly subsidized or otherwise lowered retail electricity prices (Sepulveda 2018). But facing a public backlash from increasing prices (and an upcoming election) in 2017, the government radically increased the type and number of subsidies that on a full-year basis totalled $4.7 billion in 2018. Those subsidies have continued to this day. Figure 1 shows that from 2009 to 2022 subsidies increased from $0.4 billion to $6.1 billion ($2022), or about 27 percent of system costs. This means that in 2022 only 73 percent ($17.1 billion) of system costs were recovered from rates. For the 2024–25 fiscal year, those subsidies are estimated at $7.3 billion (Ontario 2024a), equivalent to 0.65 percent of projected provincial GDP (Ontario 2024b). No other government in Canada has subsidized their electricity sector by this much for so long, making Ontario a highly subsidized sector since 2017.

Wind prices and system costs

The development of wind generation was one of the key drivers of Ontario's distinctive policy approach. Ontario's first commercial wind farm went into service in 2002, but it was not until the government implemented the Renewable Energy Supply (RES) in 2004 that wind took off in Ontario. Additional rounds occurred in 2005 (RES II) and 2007 (RES III) and the related Renewable Energy Standard Offer Program (RESOP) in 2006 (AGO 2011). The RES programs were traditional competitive auction processes, with the resulting rates in the range of $80 to 90/MWh. In contrast, the RESOP was a standard offer feed-in-tariff (FIT) mechanism that guaranteed a price of $110/MWh (Loudermilk 2017). By policy, OPG was effectively prohibited from owning or operating wind generation (MOE 2005), so that wind projects were developed, owned and operated in the form of independent power producers (IPPs), mostly by the private sector. The restructured sector facilitated this policy. For the RES and RESOP programs, the single-buyer was OPA, which signed long-term contracts with the wind projects that included a contracts-for-difference mechanism. Of Ontario's 5.5 GW wind capacity, 1.8 GW were contracted under the RES and RESOP programs. A further 1.1 GW was procured as part of the Green Energy Investment Agreement (GEIA) that was negotiated bilaterally by the province and a foreign consortium (IESO 2024d).

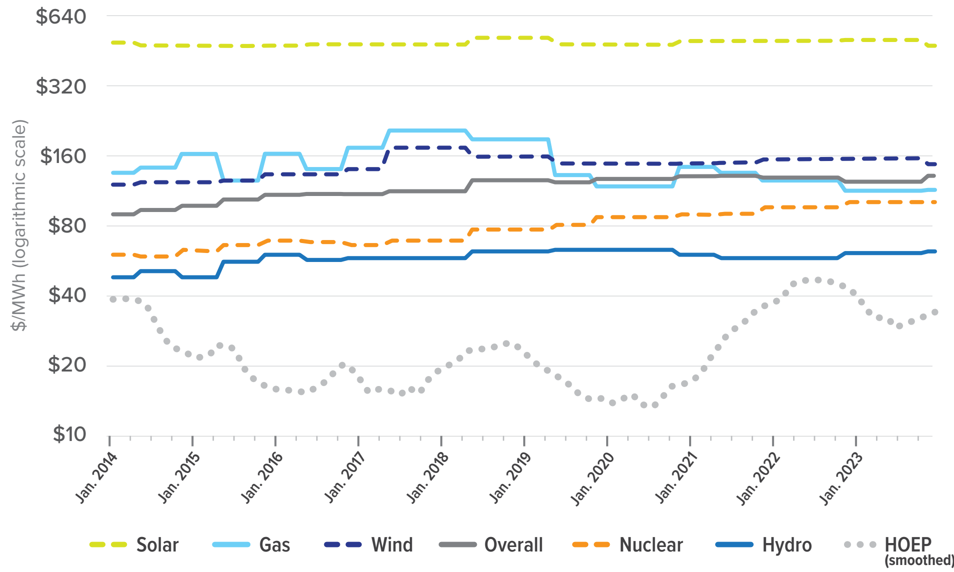
To speed up the rollout of wind and solar and meet its renewables targets, government enacted the *Green Energy and Green Economy Act* (GEA) in 2009, which would later be renamed the *Green Energy Act* before being repealed in 2018. Modelled on German legislation, its key provisions included the rollout of the standard offer FIT approach to procurement. The GEA also provided for the provincial government to override municipal opposition to the siting of wind turbines. This approach resulted in significant rural opposition to the GEA, including the adoption by some 155 Ontario municipalities of "unwilling host" resolutions (WCO 2024). A total of 2.5 GW was procured under the different FIT rounds, at an average of total FIT prices in the range of $135 to $145/MWh. Another 0.16 GW was procured in the competitive Large Renewable Procurement (LRP) with an average rate of between $85 to $90/MWh (Loudermilk 2017). Wind contracts generally had "escalation clauses" that increased the rate by one-fifth the rate of inflation (e.g. if inflation was 2.5 percent the contract rate could increase by 0.5 percent).

What is clear from the above analysis is that auction-based processes always resulted in lower prices. The government established relatively high standard offer FIT prices to increase the bankability of the wind projects and derisk sufficient entry to meet its policy goals. Figure 2 presents the result of this policy approach as it relates to wind, and other generation technologies, as well as the market price HOEP and the average overall cost of all generation.

Figure 2 shows that the price of wind is relatively very high and increases over time, due to the escalation clauses and higher-priced projects coming online. The average price for the 2014–2019 period was $143/MWh and increased to $151/MWh for the 2020–23 period. Further, because the price of wind is above the HOEP for the entire period, and due to the CfD mechanism, wind received a majority out-of-market revenues. Lastly, the wind price was always higher than the overall average cost of generation, meaning that the more wind was added to the mix, the higher the overall average generation price.

The impact that wind generation had on costs can be seen in Figure 3, which presents the same system cost data as in Figure 1, but from a different perspective. Figure 3 shows that from 2009 to 2022, wind accounted for $2.0 billion of the $4.5 billion ($2022) increase as wind increased its percentage in the generation mix from 1.6 percent to 10 percent. That is to say, wind accounted for 44 percent of the increase in generation costs and 37 percent of the overall system costs. These findings are consistent with previous research that has documented a significant increase in Ontario system costs (Bishop et al. 2020) and that wind generation has been a significant driver of that increase (McKitrick and Adams 2014).

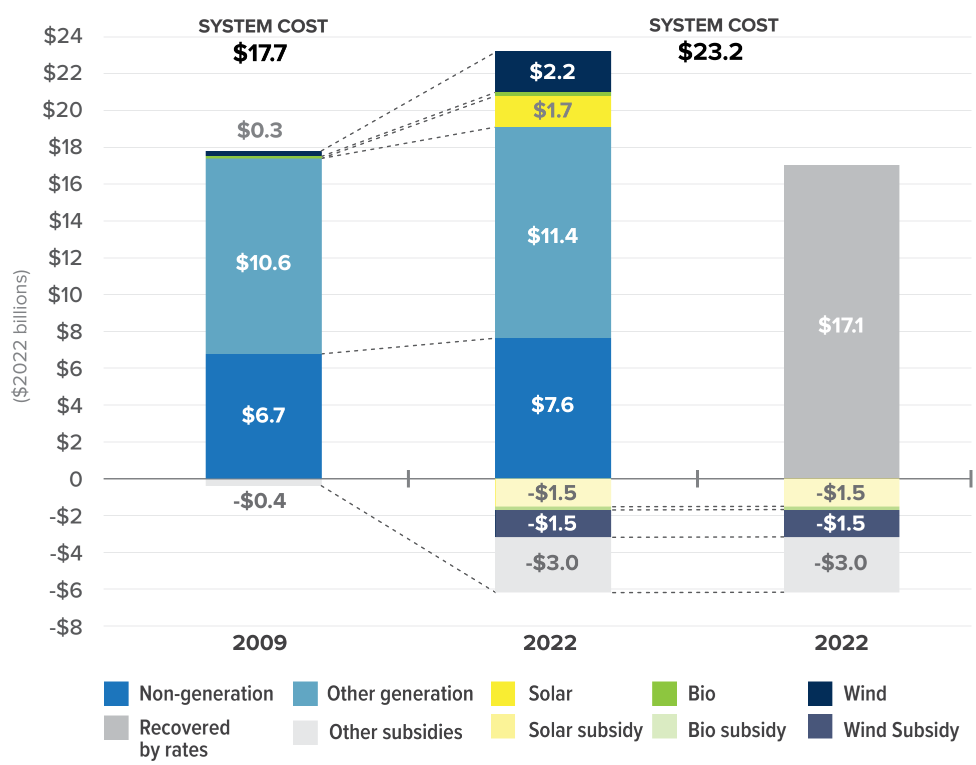
FIGURE 2: Ontario wholesale generation prices



Averages	Nuclear	Hydro	Gas	Wind	Solar	Overall	HOEP
2014–23	$79	$58	$147	$146	$488	**$117**	$25
2020–23	$94	$60	$124	$151	$494	**$128**	$30

Sources: OEB (2023 and previous), IESO (2024b), and author's calculations.

FIGURE 3: Ontario system costs: wind and subsidies



Source: MSP (2023), OEB (2023 and previous), and author's calculations.

As discussed in the previous section, in 2022 the Ontario government subsidized electricity prices to a total of $6.1 billion through a half dozen programs, some of which ear-marked specific generation segments (FAO 2022). Indeed, the largest single subsidy program is the $3.1 billion Renewables Cost Shift (RCS – also called the Comprehensive Electricity Program (CEP)), which is specifically targeted at wind, solar, and bio-mass generation (Sepulveda 2022). The wind and solar components of the RCS are $1.5 billion each, with the bio component at $0.1 billion. The other, non-RCS subsidies are $3.0 billion. The cost of wind generation from Figure 3 is $2.2 billion. Thus, wind generation received an ear-marked subsidy of about 70 percent ($1.5/$2.2) for 2022, resulting in a highly subsidized form of generation.

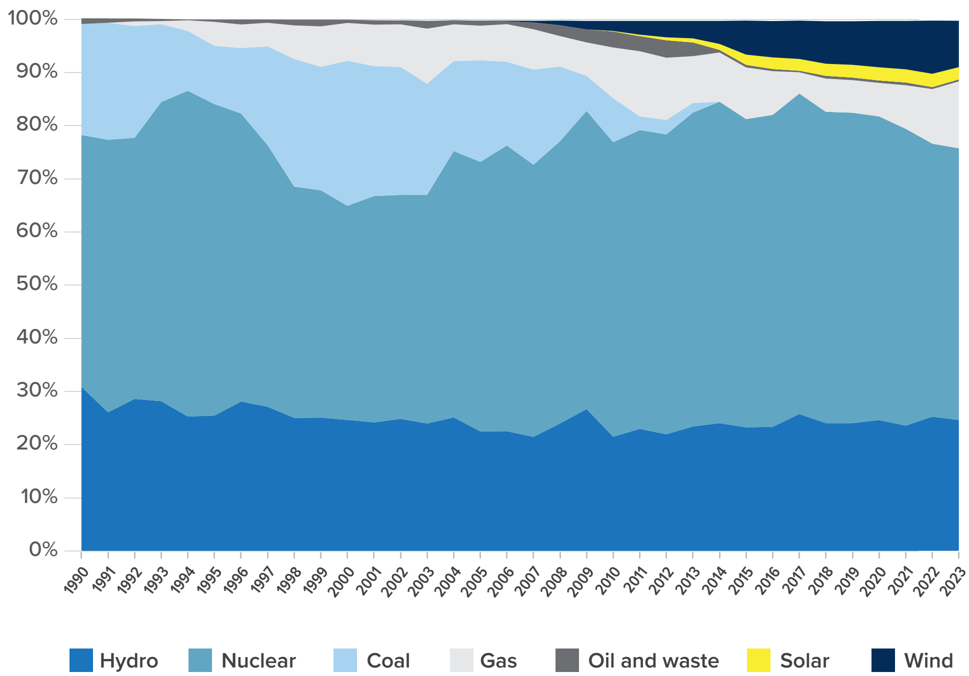
Nuclear and hydro-dominant low-emissions grid

The climate benefits of wind will generally depend on how wind interacts with the existing generation mix and its emissions intensity. On the one extreme, in a relatively high emission grid dominated by coal or oil, for instance, wind will tend to have a relatively higher climate benefit if it can displace coal or oil on a one-to-one, MWh-to-MWh basis. At the other extreme, in a relatively low emission grid dominated by nuclear or hydro with no coal, we would expect wind to have a relatively lower climate benefit. This is because it is likely to displace both non-emitting and emitting generation, and the emissions avoided from the emitting generation, such as gas, will be lower than that of coal or oil.

Ontario fits into the second category of grid where the climate benefits of wind are likely to be relatively lower. As shown in Figure 4, Ontario has a nuclear and hydro-dominant grid, with these two zero-emitting technologies accounting for between 65 percent to 85 percent of the generation mix (average of 77 percent) over the 1990–2023 period.

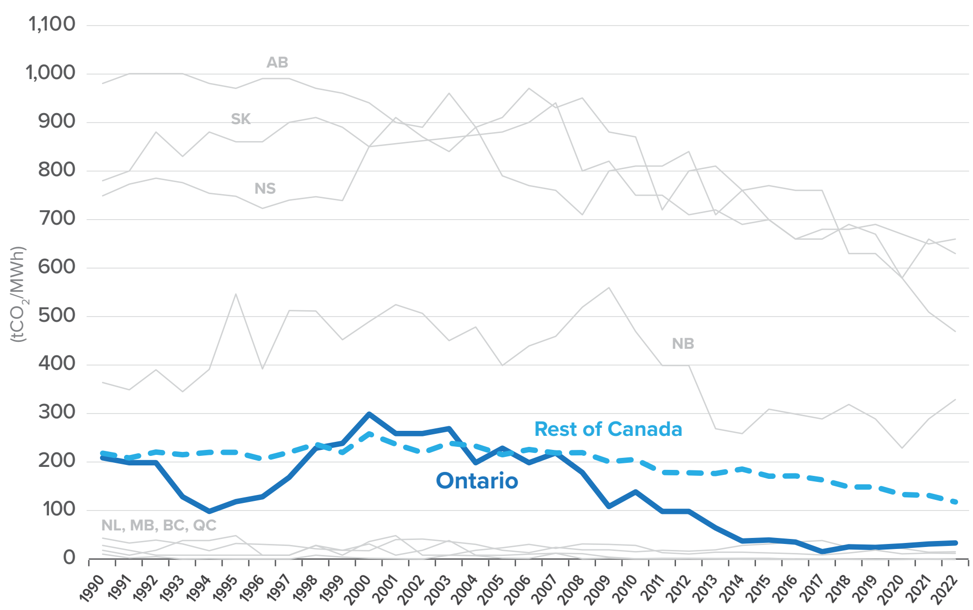
Coal generation peaked at 27 percent in 2000, based on which there was soon a concerted cross-political party consensus to eliminate it, which was achieved in 2014. From 2000 to 2014, for instance, nuclear generation increased its share by 20 percentage points, from 40 percent to 60 percent, thus accounting for 74 percent of the coal decrease (20 percent/27 percent). Wind was next with a 16 percent contribution (4 percent points/27 percent), followed by gas at 8 percent (2 percent points/27 percent), with the rest of the generating technologies making up the remaining 2 percent.

FIGURE 4: Ontario Generation mix



Sources: Canada (2024 and previous), IESO (2024c and previous), and author's calculations

FIGURE 5: Provincial electricity GHG emission intensity



Sources: Canada (2024, and previous), author's calculations.

Figure 5 shows the evolution of generation emission intensity from 1990 to 2022 for Ontario, the other provinces, and the "Rest of Canada" (all provinces and territories). Due to it being a nuclear and hydro-dominant province, Ontario has been at or well below the Rest of Canada for most of the 1990–2022 period. Indeed, since the elimination of coal, Ontario is one of the lowest-emissions larger grids (>100 TWh/year) in the world, with emissions intensity below 50 tons of carbon dioxide (tCO_2) per MWh every year since 2014, with an average of 32 tCO_2/MWh over the 2014–2022 period.

Wind profile and correlation with demand

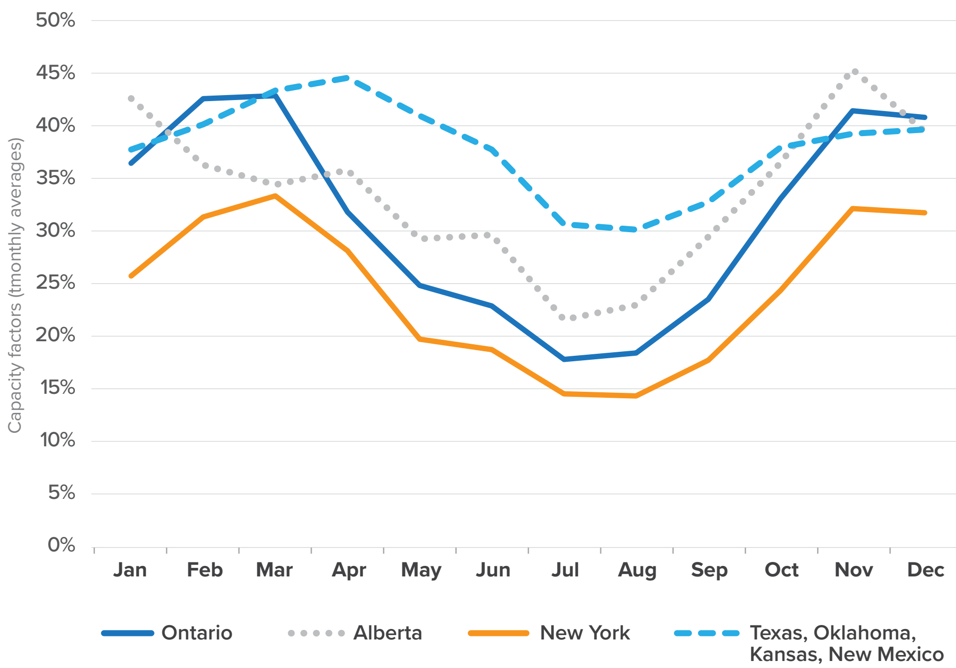
The climate benefits of wind will also depend on its particular profile in Ontario, including capacity factors over the year, and how that correlates with emitting generation and demand.

To compare Ontario's actual wind profile, we collected average monthly capacity factors from three other regions, as presented in Figure 6. This type of historical comparison is in contrast to studies that assess potential wind generation or other modelling analysis. For comparison we include New York because we would expect its profile to be comparable to that of Ontario (NYISO 2024, and previous). We also include two prairie/plains comparisons, Alberta (AESO 2024) and the "Lower Plains," as defined by the U.S. Energy Information Administration that includes Texas, Oklahoma, Kansas, and New Mexico (EIA 2022). The periods included in Figure 6 are 2019–2023 for NYISO and AESO, 2020–23 for Ontario, and 2016 to mid-2022 for the Lower Plains.

Except for Alberta, the other profiles in Figure 6 show some form of an "M" shape, with twin peaks around March and November and a pronounced trough in July-August. In contrast, the West Coast of Canada and the US (not shown) have an inverted "U" shape. Ontario's monthly capacity factors are always higher than that of New York, indicating that Ontario has a superior wind profile. However, Ontario's average capacity factor of 31 percent is lower than that of Alberta (34 percent) and of the Lower Plains (38 percent). As shown in Figure 6, Ontario generally compares favourably to these other regions during the peaks. It is Ontario's more pronounced and prolonged summer trough that brings down its average annual capacity factor.

One of the innovations of this report is that the regression and cost-benefit analysis considers this seasonal variation. Indeed, for the rest of the report

Figure 6: Average monthly wind capacity factors



	Averages	StdDev	Norm StdDev
Ontario	31%	9.1%	0.29
Alberta	34%	7.0%	0.21
New York	24%	6.8%	0.28
Texas, Oklahoma, Kansas, New Mexico	38%	4.4%	0.12

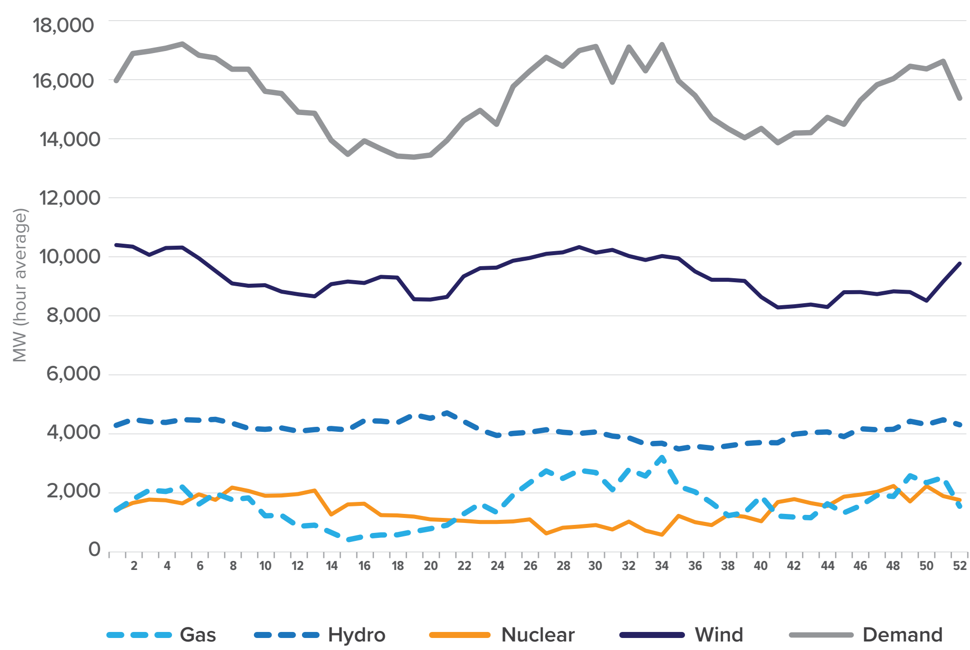
Sources: AESO (2024), EIA (2022), NYISO (2024 and previous), and author's calculations.

we use weekly data, Week 1 to 52 of the year, to more accurately capture this seasonality. We construct a custom database for the four most recently available years, 2020 to 2023, based on publicly available data (IESO 2024b). We use this database in this chapter to graphically present the results and in Chapter 3 as the basis for the regression and cost-benefit analyses. This hourly data is only available for transmission-connected generation, which covers 92 percent of all generation, with distribution-connected capacity making up the remaining 8 percent, with the ratio for wind being 89 percent/11 percent respectively (IESO 2024c).

For our database we use the hour as the basic unit of analysis and group all hours in seven-day periods from January 1 of every year, from Week 1 to Week 52. Fifty-two 7-day weeks adds up to 364 days, so we need to add an eighth day to one of the weeks. Each of the weeks from Week 1 to Week 51 have seven days thus a total of 672 hours (24 hours x 7 days x 4 years). Week 52 will get an extra day thus having 768 hours (24 hours x 8 days x 4 years). For analytical purposes we exclude the 24 data points for February 29 of 2020, a leap year.

Figure 7 shows the average hourly demand and generation for the years 2020–23, by week of the year. Ontario demand has two troughs and two peaks. The troughs are Weeks 15 to 20 in spring, and Weeks 39 to 43 in the autumn. There is a summer peak in Weeks 27 to 34 and a winter peak from Weeks 49 to 7. The summer peak is associated with higher space cooling and the winter peak with higher space heating and industrial use. Over the year, demand averaged

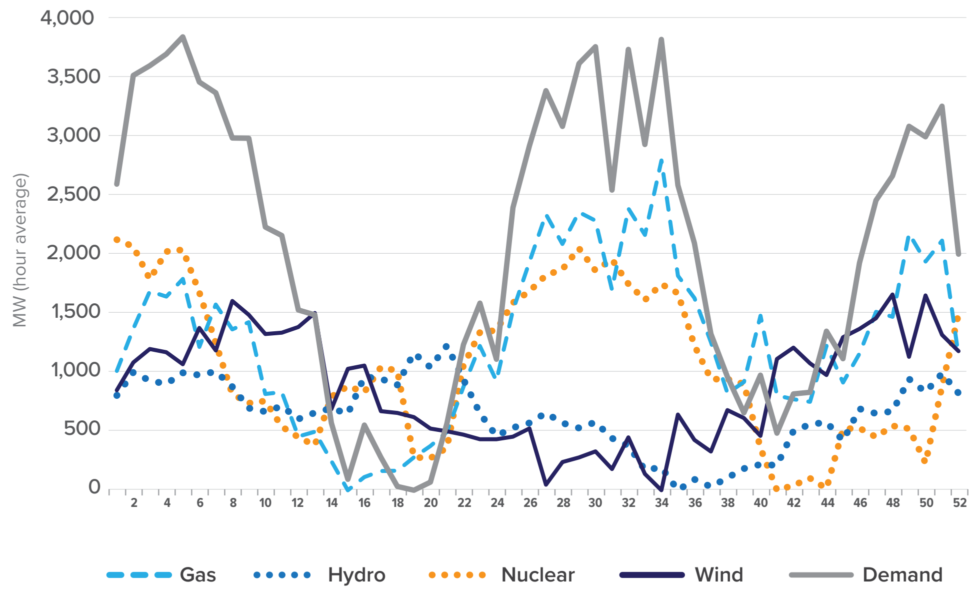
FIGURE 7: Ontario demand and generation 2020–23, by week



	Gas	Hydro	Nuclear	Wind	Demand
Average	1,661	4,115	9,324	1,425	15,422
StdDev	683	302	641	460	1,209
Normal StdDev	0.41	0.07	0.07	0.32	0.08

Sources: IESO (2024b), author's calculations.

Figure 8: Ontario demand and generation (from minima) 2020–23, by week



	Correlation	
	Demand	Gas
Nuclear	0.649	0.539
Hydro	0.032	-0.267
Wind	0.047	-0.266
Gas	0.862	1.000

Sources: IESO (2024b), author's calculations.

15,422 MW and had a normalized standard deviation of 0.08. Wind averaged 1,425 MW with a normalized standard deviation of 0.32.

Figure 8 shows the same data as in Figure 7, but this time setting the respective minima at zero for each series. For example, Figure 8 shows the two trough/two peak Ontario demand profile and highlights that nuclear is positively correlated with Ontario demand (correlation co-efficient = 0.649). The correlation coefficient measures the strength of the relationship between two variables, going from -1.00 (perfect negative correlation means that two variables move in opposite direction all the time), to 1.00 (perfect positive correlation means that two variables move in the same direction all the time), with 0.00 meaning uncorrelated.

This type of nuclear seasonal "load following" is made possible by planning maintenance outages for Ontario's fleet of 18 nuclear reactors in a coordinated manner consistent with Ontario demand. Gas generation is very strongly correlated with Ontario demand, with a correlation co-efficient of 0.862, reflecting its "peaking" function. In contrast, wind generation is uncorrelated with Ontario demand, with a coefficient of 0.047. Figure 8 also includes correlation data with gas and shows that wind is negatively correlated with gas generation, with a coefficient of -0.266. This indicates that wind did not efficiently displace gas in Ontario. We explore this in further detail in the following chapter.

Regression and cost-benefit analysis

In this chapter we undertake regression analysis to assess how wind generation interacted in Ontario's nuclear and hydro-dominant grid for the four years from 2020 to 2023. We apply these regression results to a historical cost-benefit analysis of wind generation for the 2020–2023 period and a forward-looking cost-benefit analysis for the 2027–2030 period.

Regression analysis for 2020–23

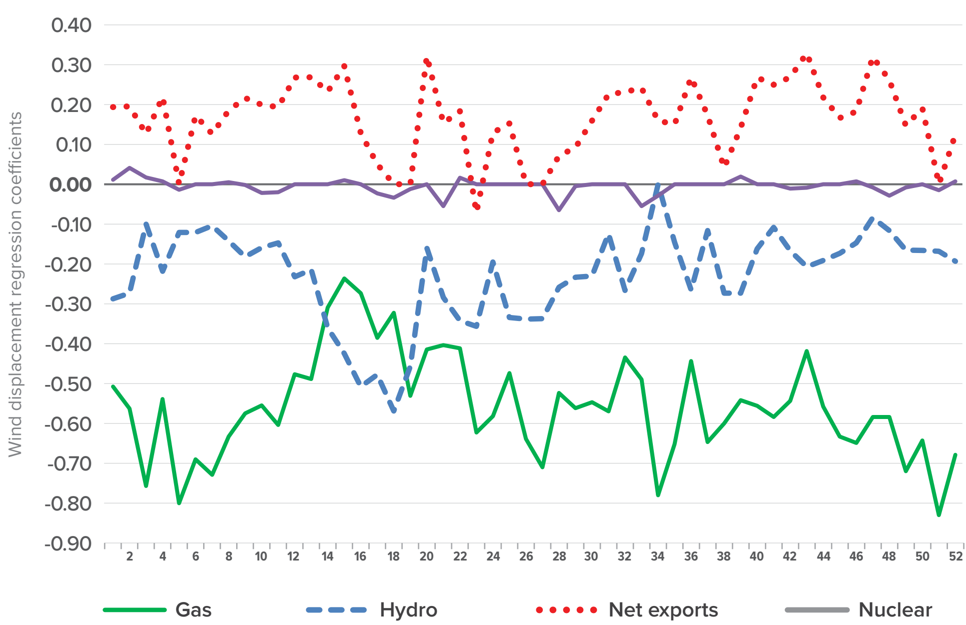
Our regression analysis is designed to estimate the manner wind generation interacted with the rest of the Ontario grid over the 2020–23 period. As set out in the Appendix, our objective is calculating regression coefficients that quantify whether and by how much wind generation is statistically associated with decreases or increases of other types of generation. In our case, we focus on the three largest generation technologies in Ontario, nuclear, hydro and gas. We also model whether and by how much wind generation increases/decreases net exports (NX) from/to other provinces and the US.

Our work differs from previous research by specifically considering the seasonal variation of wind by calculating separate week of year regressions over the 2020–23 period. In summary, beginning from available hourly transmission-connected generation from IESO, we pool hourly data by the week of the year as described in Chapter 2. We then we carry out 208 regressions, one for each of the week of the year (52) for four variables (gas hydro, nuclear, and NX).

Figure 9 presents the results of the wind interaction coefficients for the 208 regressions. Statistically significant coefficients are presented by their coefficient results; insignificant results are presented as zero. Overall, the regression results were strong, with relatively high adjusted R^2 and other significance parameters (see Appendix for regression methodology and more detailed results). These coefficient results indicate that on average 1.00 MWh of wind generation was statistically associated with the following: a decrease (displacement) of -0.56 MWh of gas, a decrease (displacement) of -0.23 MWh of hydro, an increase (contribution) of 0.17 MWh to NX and had a minimal impact (-0.01 MWh) on nuclear. These results indicate that in Ontario's low-emissions nuclear and hydro-dominant grid, only about 56 percent of wind output goes to displacing gas generation.

Figure 9 highlights the importance of seasonal variation around these annual averages. During the winter peak of Ontario demand in Week 5, for example, it shows that each 1.00 MWh of wind displaced -0.80 MWh of gas. For the same Week 5, wind displaced -0.12 MWh of hydro. On the other hand,

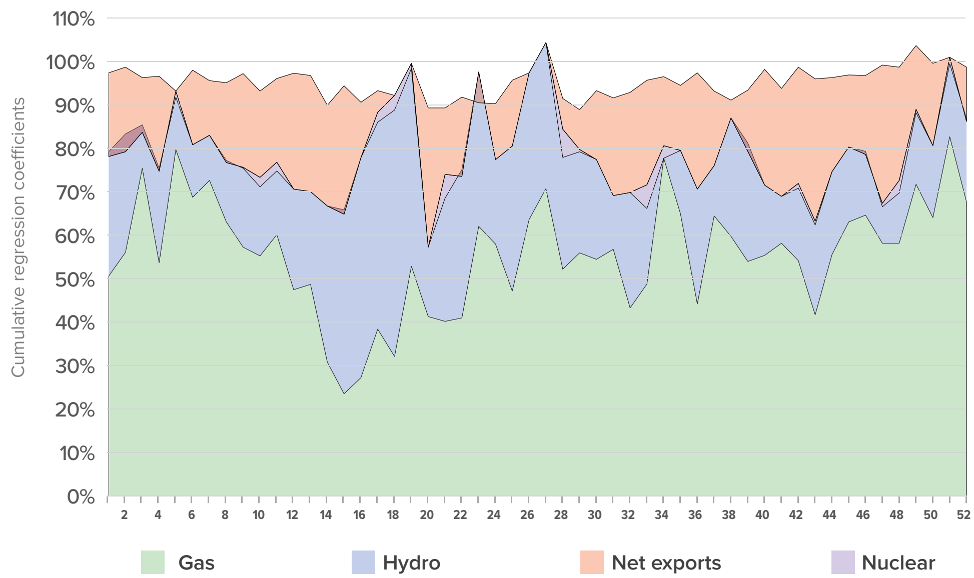
FIGURE 9: Wind regression coefficients, by week



	Gas	Hydro	Net exports	Nuclear
Average	-0.56	-0.23	0.17	-0.01
StdDev	0.13	0.12	0.09	0.02

Source: Author's calculations.

FIGURE 10: Cumulative wind regression coefficients, by week



Source: Author's calculations.

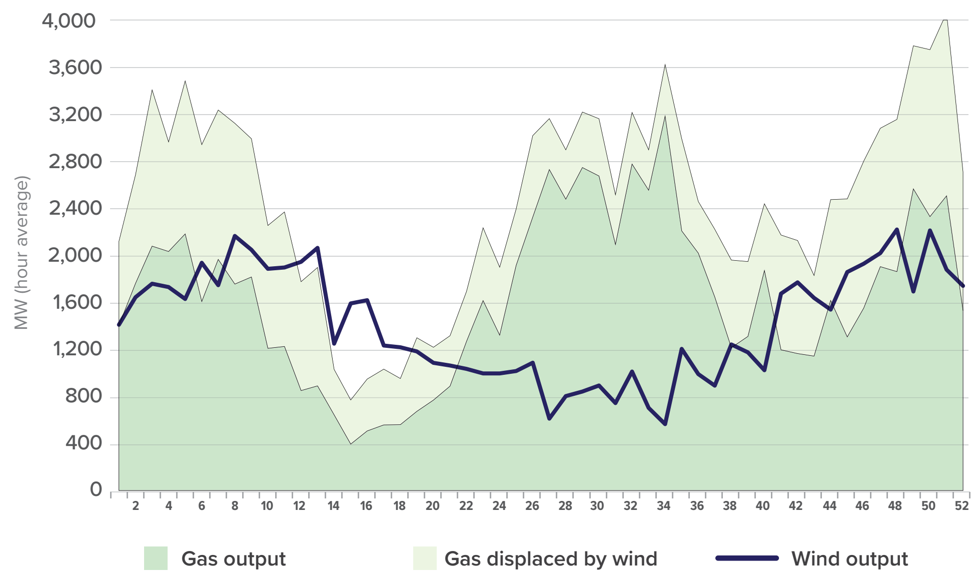
over the summer Ontario demand peak of Weeks 29 to 35, 1.00 MWh of wind on average displaced -0.58 MWh of gas, -0.17 MWh of hydro, and contributed 0.18 MWh to NX. The climate benefits associated with wind displacing gas, therefore, depend on the week of the year.

Another manner of presenting the regression results is by adding the absolute values for each of the four coefficient results over the 52 weeks, as shown in Figure 10. This figure shows that these add to approximately 100 percent for every week, confirming that the four regressions are capturing virtually the whole of the wind interaction in the Ontario grid over the entire year.

How much gas is wind displacing over the year? Figure 11 shows average gas output, the amount of gas displaced by wind and wind output. To be clear, the displaced gas did not occur – it is an estimate of the gas that would have occurred had wind not existed. It is the gas avoided. During Week 5, for instance, wind displaced about 1,302 MW of gas generation per hour. In contrast, during Weeks 29 to 34, wind displaced an average of only 434 MW of gas per hour. These results confirm that climate benefits of wind displacing gas depend on the week of the year.

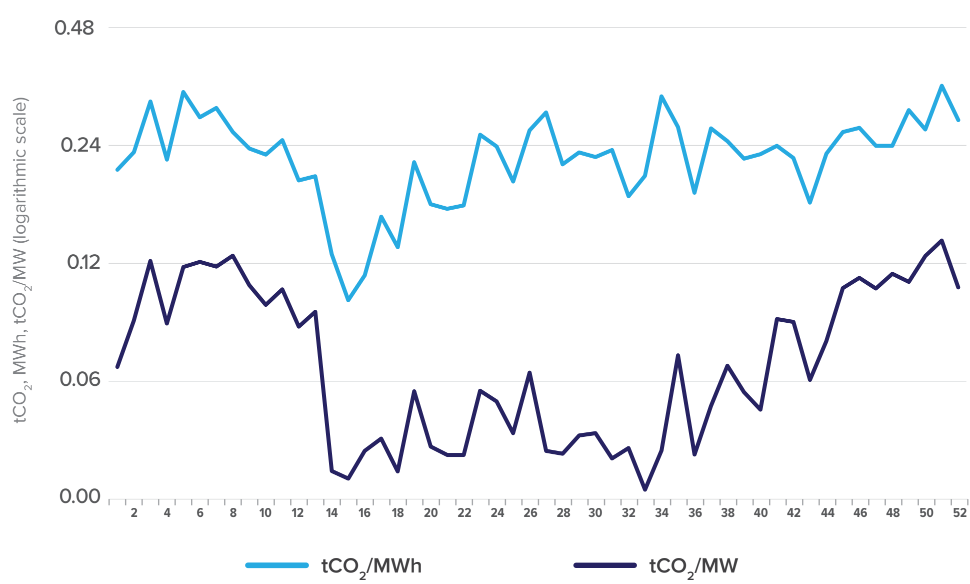
Figure 12 shows these climate benefits directly, by showing how much CO_2 is avoided by wind. It shows that on average 1.00 MWh (generation) of wind

Figure 11: Gas generation and displacement 2023–23, by week



Sources: IESO (2024b), Author's calculations.

Figure 12: tCO_2 reductions due to wind 2020–23, by week



	Average	StdDev	Norm StdDev
tCO_2 avoided per MWh	0.227	0.052	0.23
tCO_2 avoided in one hour per MW	0.072	0.031	0.44

Source: Author's calculations.

displaces 0.227 tCO_2 (the wind emissions offset), and that 1.00 MW (capacity) of wind displaces 0.072 tCO_2 per hour the wind capacity emissions offset. This confirms that the capacity and output avoided CO_2 ratio (0.072/0.227) is the same as average wind capacity factor (31 percent). From a capacity perspective, Figure 12 shows that the capacity value of wind with respect to climate are lowest in weeks 14 to 34, during which 1.00 MW displaces only 0.043 tCO_2 per hour.

Cost-benefit analysis for 2020–23

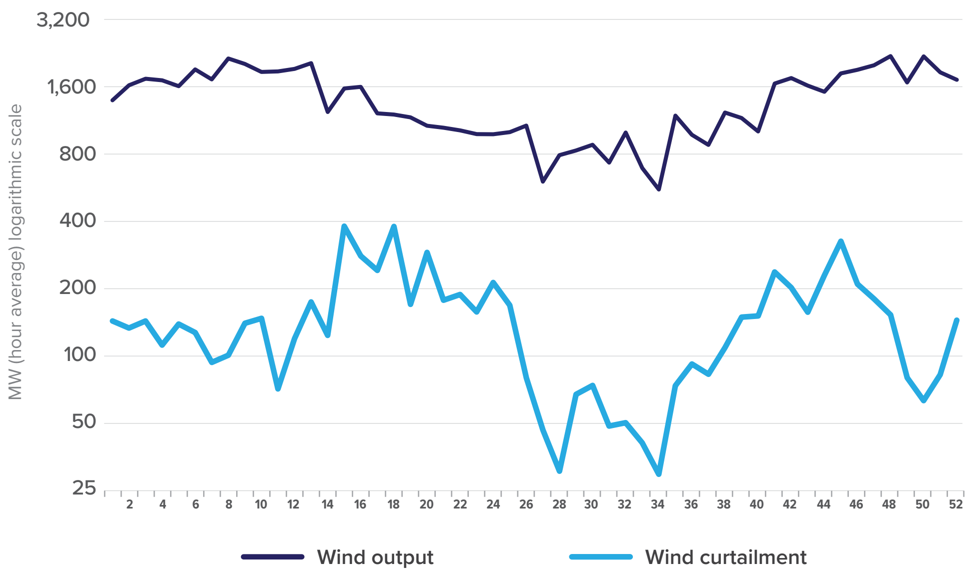
The analysis presented in Chapter 2 indicated that in Ontario wind was generally higher priced and so that as it increased its participation in the generation mix it was disproportionately responsible for higher system costs, which resulted in it being highly subsidized. This section expands this analysis to assess the cost-benefit of a more comprehensive perspective, including estimating the financial impacts of how wind interacts with the other modelled generation resources and NX, as well as placing a monetary value on the avoided CO_2 emissions in the form of the Social Cost of Carbon (SCC). From an Ontario perspective, there are two elements on the cost side, and four elements to the benefit side of the cost-benefit analysis, which we discuss below.

Cost analysis

There are two elements on the cost side: the expenses associated with wind output and with wind curtailment. Average annual wind output expenses are equal to average output over the 2020–23 period (12.5 TWh) times the average wind price over the same period ($151/MWh).

Ontario has been a net exporter of electricity since the late-2000s, mostly driven by a condition that IESO refers to as "surplus baseload generation" (SBG), which occurs when electricity production from nuclear, hydro, wind, and solar is greater than Ontario demand (OPG 2024). For grid stability purposes IESO must balance surplus and deficit power situations. IESO's first "escape valve" in surplus situations is to increase exports; the second is to reduce Ontario generation, including wind generation. Such wind reductions are referred to as "curtailment." As in other jurisdictions, wind IPPs are compensated for curtailment. IESO calculates the estimated capability for every wind turbine in Ontario based on a series of parameters, including available installed capacity, and actual wind speed at the location, based on sensors. The difference between

Figure 13: Ontario wind output and curtailment 2023–2023, by week



Sources: IESO (2024b), author's calculations.

actual and IESO forecast wind generation is referred to as "curtailed wind." Average annual expenses associated with wind curtailment is equal to average wind curtailment over the 2020–23 period (1.3 TWh) times the average wind price over the same period ($151/MWh).

Figure 13 shows average hourly wind generation and curtailment for the 2020–23 period. Curtailed wind is highest during the hydro peak freshet in Weeks 16 to 21 and lowest during the Ontario summer demand peak in Weeks 27 to 34. In operational terms wind curtailment is implemented by idling some or all turbines at a particular site.

Benefits analysis

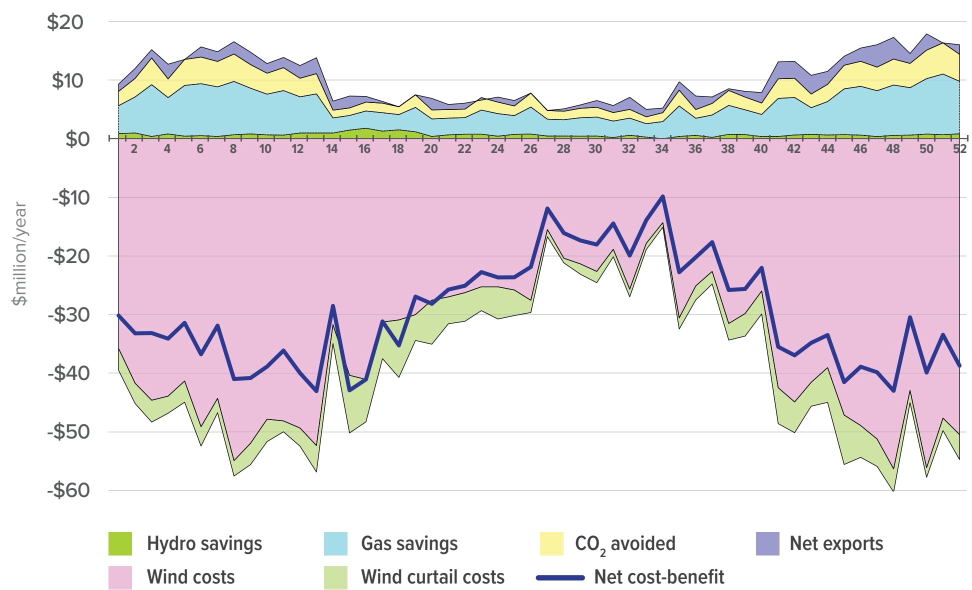
There are four elements on the benefits side: the financial savings from decreased hydro and gas generation, the increased revenues from increased NX, and the financial benefits from avoided CO_2. We do not include any financial impact of nuclear given wind's minimal impact on this form of generation. Because of specific financial provisions discussed below, it is important to highlight that there is a difference between effective price of a wind-displaced MWh of hydro and gas and their respective "sticker" prices, as presented in Figure 2.

Our regression-based estimates indicate that wind decreases hydro generation by an average of 2.7 TWh/year over the 2020–23 period. We calculate the effective price of that reduction by associating wind-related decreased hydro generation with forgone hydro production due to SBG conditions. OPG, which has 84 percent of Ontario's hydro resources, reported forgone production of 2.2 TWh/year over the 2020–23 period (OPG 2024, and previous), so that for the sector as whole that would be 2.6 TWh/year, very close to the regression-based estimates. OPG was compensated for its forgone hydro generation at $30/MWh based on series of OEB-approved deferral accounts (OPG 2024, and previous). During this period OPG's regulated hydro rate was $43/MWh, so the difference between that and the compensated price ($30/MWh) equals the per MWh savings from wind-decreased hydro ($13/MWh).

As discussed above, gas generation in Ontario is used as peaking and to back up wind and solar and not as "baseload," and is not generally subject to SBG-related reductions. The way gas has been contracted reflects its profile in Ontario. Indeed, about 70 percent of gas generation is contracted under deemed revenue monthly payments designed to promote the availability of gas capacity when it is needed. In summary, for each different gas plant IESO establishes a fixed dollar amount to pay for fixed capital and operational costs, as if there was no gas generation. From that amount IESO subtracts the net revenues that specific generator should have earned ("deemed revenues") in the market, after paying for the natural gas and other approved variable costs. Deemed hours of generation are those during which the HOEP exceeded the specific operator's approved net variable costs. To ensure stand-by capacity, this system "tops up" net energy revenues with a form of capacity payment to "make whole" the generators. Under this specific contractual arrangement, the financial savings from displaced gas generation is equal to the value of the natural gas and other approved variable costs. The gas generation savings therefore are based on the average 2020–23 Dawn Hub natural gas price ($4.50/MMBtu) multiplied by the gas saved (54.1 million MMBtu/year). This is equivalent to $34.5/MWh for 7.0 TWh, to which we add $5/MWh as a proxy for the other variable costs.

We calculate revenues from NX by multiplying the average regression-based additional NX for the 2020–23 period (2.2 TWh) by the average NX price of $37/MWh. For the financial valuation of avoided CO_2 we use a SCC

FIGURE 14: Cost-benefit of wind generation, 2020–23



Wind price ($/MWh)	$151
Hydro savings ($/MWh)	$13
Gas savings ($/MWh)	$40
NX revenues ($/MWh)	$37
SCC ($/t$CO_2$)	$50
Wind cost-benefit ($/MWh)	**-$124**

Sources: Author's calculations.

of $50/t$CO_2$ (Bahramian et al. 2021, Canada 2018) and multiply it by the avoided emissions (2.9 MtCO_2) associated with the displaced gas.

The summary results of the 2020–23 cost-benefit analysis are presented in Figure 14, which includes the two cost and four benefit elements as well as the overall cost-benefit, all by week of the year. To facilitate comparisons with other scenarios, we calculate the cost-benefit result on a MWh basis, at -$124/MWh. This means that the costs of wind generation in Ontario during the 2020–23 period far exceeded the corresponding climate and other benefits. This result is driven by the relatively high contracted wind price over the period ($151/MWh) and by our finding that while wind displaced some gas generation, it also displaced lower priced zero-emission hydro and contributed to lower priced NX.

Cost-benefit analysis for 2027–2030

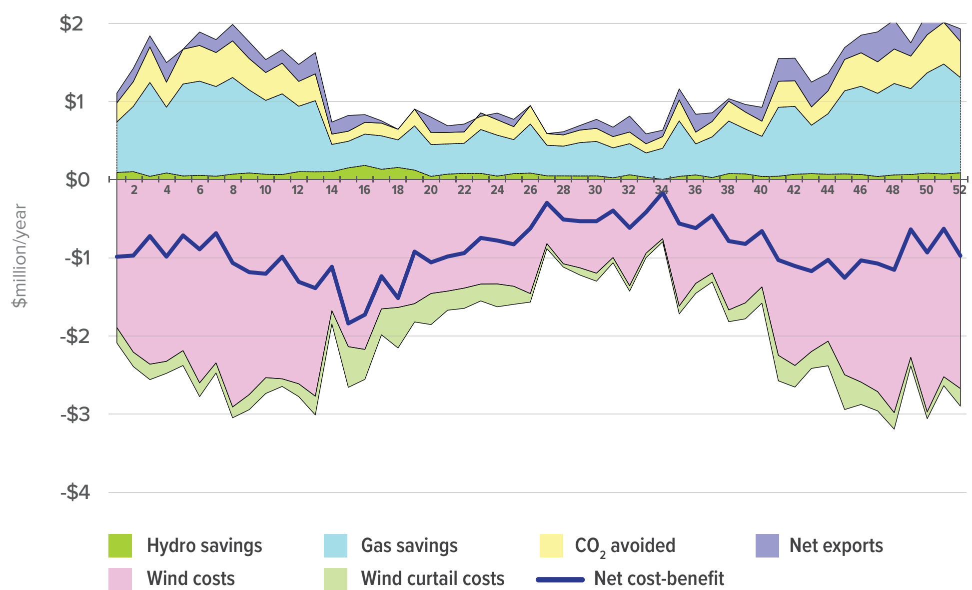
In this section we undertake a forward-looking cost-benefit analysis for the 2027–2030 period. We chose this period because it is relatively soon from an energy system perspective, and hence the regression parameters that we calculated for 2020–23 are likely to remain reasonably valid. Our analysis serves for two scenarios. One is for the legacy wind projects whose 20-year contracts would expire in and around this period. These could include the RES, RESOP and early FIT wind projects contracted in the 2004 to 2010 period. As it has for other resources whose contracts have expired, there could be a mutual interest between IESO and wind IPPs to re-contract, depending on operational state of the resources. Our study provides an assessment of the price at which such a re-contracting could be cost-beneficial. Our work also serves to provide insight into the cost-benefit of new wind projects.

Conceptually, the biggest difference between the cost-benefit analysis of legacy or new projects would be the inclusion in the latter of the system and other costs of adding new wind. This would include new transmission resources to enable the expansion of wind, possibly new back-up or storage facilities and related ancillary services. While this type of detailed modelling is outside the scope of this study, it is important to keep in mind that these incremental costs are likely to be significant. For example, IESO estimates that the average cost of new transmission to 2050 for wind projects is in the range of $25/MWh (IESO 2022).

For the 2027–2030 scenario we maintain most of the same parameters that we used for the 2020–23 analysis: same regression parameters, same baseline generation, same SCC and NX prices. We update the natural gas price based on the average 2027–2030 forecast used by IESO, of $6.35/MMBtu (IESO 2024a). As a base, we use a (rounded) reference wind price of $80/MWh, based on applying Ontario's wind capacity factor of 31 percent to a recent levelized cost of energy (LCOE) study for wind for 2022 (NREL 2023). Given the recent trajectory of wind LCOEs and uncertainty over its future evolution, we use the same nominal amount of $80/MWh for the 2027–2030 period.

Figure 15 presents the results for the 2027–2030 period, with a cost-benefit result of -$38/MWh. This result is based on a 10 percent increase in wind generation relative to the baseline amount, but the size-normalized result of -$38/MWh equally applies to both re-contracted legacy and new wind projects.

Figure 15: Cost-benefit of wind generation, 2027–2030



Wind price ($/MWh)	$80
Hydro savings ($/MWh)	$13
Gas savings ($/MWh)	$54
NX revenues ($/MWh)	$37
SCC ($/t$CO_2$)	$50
Wind cost-benefit ($/MWh)	**-$38**

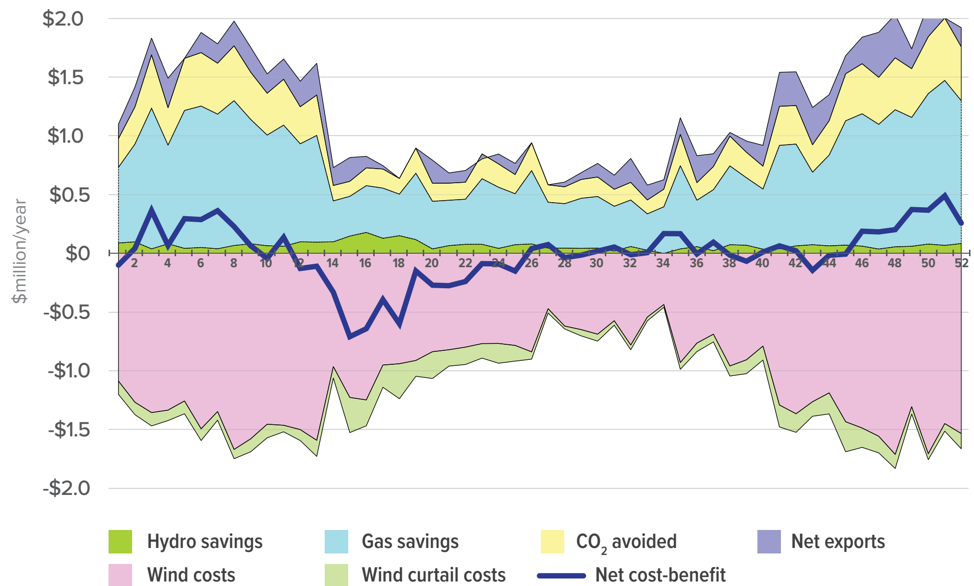
Source: Author's calculations.

These results suggest that even at the lower reference price of $80/MWh relative to the $151/MWh that held during the 2020–23 period, the costs associated with wind generation still exceed the corresponding climate and other benefits.

Sensitivity analyses for 2027–2030

There are an infinite number of possible variations of the baseline and reference amounts to test the sensitivity of the reference 2027–2030 results. For example, Figure 16 shows that $46/MWh is the "break-even" wind price required to set the cost-benefit = $0/MWh. Figure 16 shows that around the average there is significant variation, so that the negative cost-benefit during Weeks 13–27 is offset with the positive results during most of the rest of the year. The break-even price of $46/MWh is well below both the actual average 2020–23 price of $151/MWh and the LCOE-based reference price for 2027–2030 of $80/MWh.

Figure 16: Price-varying break-even scenario, 2027–2030



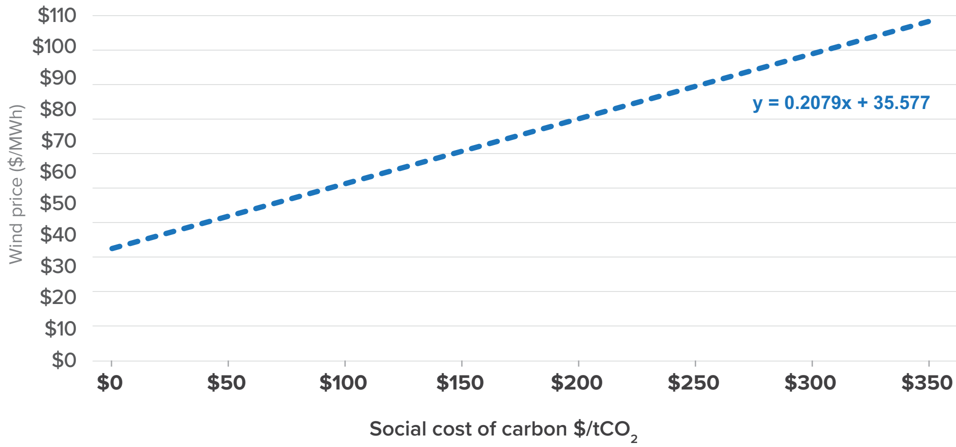
Wind price ($/MWh)	$46
Hydro savings ($/MWh)	$13
Gas savings ($/MWh)	$54
NX revenues ($/MWh)	$37
SCC ($/t$CO_2$)	$50
Wind cost-benefit ($/MWh)	**$0**

Source: Author's calculations

This sensitivity analyses can be generalized. Figure 17 presents the break-even cost-benefit isoline that results from varying the SCC and wind price. The line has a slope of $0.2079 and a constant of $35.577, meaning that every $1 increase in the SCC raises the break-even price by $0.2079/MWh. For example, using a SCC of $0/t$CO_2$ would result in a break-even wind price of $35.577/MWh. Setting it at $50/t$CO_2$ (Bahramian et al. 2021, Canada 2018) gives us the $46/MWh result noted above. Further increasing the SCC to $150/t$CO_2$ (Canada 2021) results in a wind price of $67/MWh. Increasing the SCC to $350/t$CO_2$ (Canada 2023) yields a break-even wind price of $108/MWh. All these prices in comparison to $151/MWh for the 2020–23 period.

Another sensitivity analysis is presented in Figure 18, which shows the break-even cost-benefit isoline that results from varying the natural gas price

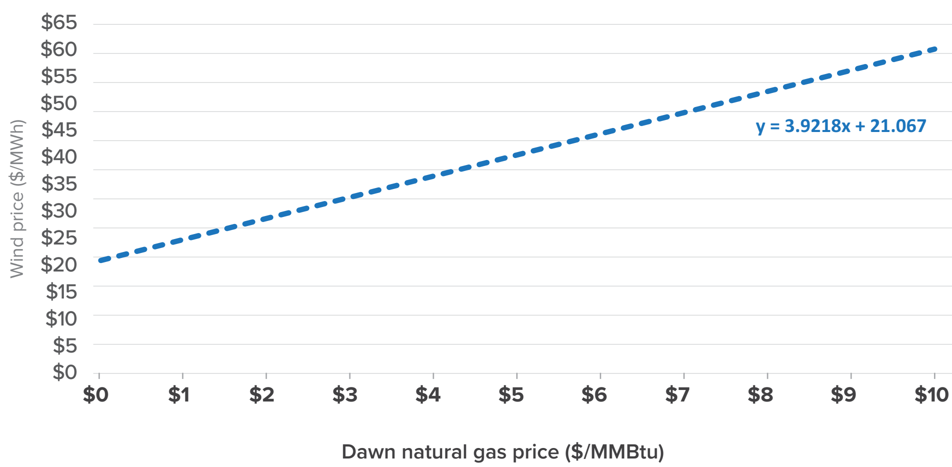
Figure 17: Break-even isoline for SCC and wind prices, 2027–2030



2003-2023 wind price $/MWh)	$151
Wind price ($/MWh)	Varies
Hydro savings ($/MWh)	$13
Gas savings ($/MWh)	$54
NX revenues ($/MWh)	$37
SCC ($/t$CO_2$)	Varies
Wind cost-benefit ($/MWh)	**$0**

Source: Author's calculations

Figure 18: Break-even isoline for natural gas price and wind price, 2027–2030



2003-2023 wind price $/MWh)	$151
Wind price ($/MWh)	Varies
Hydro savings ($/MWh)	$13
Gas savings ($/MWh)	$54
NX revenues ($/MWh)	$37
SCC ($/t$CO_2$)	$50
Wind cost-benefit ($/MWh)	**$0**

Source: Author's calculations

and wind price. For example, using the lowest annual average gas price during the 2015–2023 period of \$2.5/MMBtu (in 2020) yields a break-even wind generation price of \$31/MWh. Setting it at the average 2020–23 of \$4.50/MMBtu gives us \$39/MWh. Setting it at its reference value at \$6.35/MMBtu results in a break-even price of \$46/MWh discussed above. Increasing the natural gas price to \$10/MMBtu (which was near the highest monthly average in the 2020–23 period during the energy crises) would result in a break-even wind generation price of \$60/MWh. All these prices are in comparison to the 2020–23 wind price of \$151/MWh or the LCOE-based reference price of \$80/MWh.

Comparison with the literature

Our regression results are comparable to those of an earlier Ontario study (Bahramian et al. 2021) suggesting that the results are robust relative to level of data aggregation and to time period. We also calculated a wind emissions offset of 0.227 tCO_2/MWh and a wind capacity emissions offset of 0.072 tCO_2/MW per hour.

For the Texas grid (Cullen 2013) calculated the following wind coefficients: -0.18 for coal, -0.85 for gas, and very small impacts for nuclear, hydro and others and a total wind emissions offset of 0.561 tCO_2/MWh. At a capacity of 5.0 GW, Novan (2015) estimated a wind emissions offset of 0.670 tCO_2/MWh. Fell and Johnson (2021) estimated in-region wind emissions offsets ranging from 0.15 to 0.59 tCO_2/MWh across the nine US regions study, including 0.53 tCO_2 for Texas.

These other studies confirm that the regression and emissions offsets results vary by region depending on how wind interacts with the specific generation mix, and specifically the extent to which it displaces higher (coal and oil) or lower-emitting (gas) technologies. Ontario's wind emission offset of 0.227 tCO_2/MWh is relatively low, at only 43 percent of Texas (0.227 vs. 0.53 tCO_2/MWh), for instance. This reflects that in Ontario one MWh of wind displaces only about half a MWh of gas, a relatively lower-emitting technology, compared to other regions where wind tends to displace relatively more coal and/or gas. Likewise, because of Ontario's relatively modest wind capacity factor, its wind capacity emissions offset is relatively even lower than Texas at just 37 percent (0.072 vs. 0.196 tCO_2/MW per hour).

Policy discussion

Our analysis can inform policy options with respect to legacy and new wind projects.

For legacy wind projects whose contracts expire before 2030 the choice faced by owners will be either to decommission or to continue operations either "as is" or under partial/full repowering. Financially, the wind IPPs would recognize that re-contracting at or near $151/MWh is unlikely to be politically or economically feasible and that continuing operations could be done under a new contract with IESO or uncontracted, either a pure HOEP-only market merchant or with a third party Power Purchase Agreement (PPA). From an IESO perspective, our analysis is clear that the societal break-even contract price is about $46/MWh. The LCOE-based reference price of $80/MWh is based on new builds, not on long-term operation. Assuming that the initial wind project financing in Ontario was for 20 years or less, at contract termination the incremental costs of long-term operation with no or modest partial repowering could well be at or below $46/MWh. In comparison, the relative attractiveness of the HOEP-only alternative would depend on long-term forecasts of the HOEP. The HOEP averaged $30 during 2020–23 period, with an annual peak of $47 in 2022 during the energy crisis.

One approach would be for IESO to design and offer a wind re-contracting standard offer of $46/MWh for a maximum of a ten-year CfD-type mechanism. Wind IPPs would then be able to determine their decommissioning/continuation business decision based on this standard offer and their specific situation, including expected lifetime of existing equipment and long-term costs of operation. Some wind operations would shut down, some will recontract with IESO, and some may continue operations either under a third party PPA or be pure merchant. By way of reference, for the Eastern US the average PPA in 2021–22 was about $65/MWh (DOE 2023).

On a stand-alone basis, not considering incremental transmission and other system costs, a similar cost-benefit perspective applies for new wind projects. From an IESO perspective, the same societal break-even contract rice of about $46/MWh applies. However, the new build-based reference price results in a large gap between the social price ($46/MWh) and the private cost ($80/MWh). There are a number of options in this regard.

One option is to continue to move forward under the current private wind IPP contractual approach and for the IESO to design a competitive auction process with a maximum "reserve price" of $46/MWh. The reserve price is a critical because if it is set too high it could lead to a low value for money result for the public, but if set too low, wind IPPs may decide not to participate because it does not meet their target weighted average cost of capital (WACC).

Another possibility is to discard the contractual approach in favour of financing and compensating wind projects based on cost-of-service economic regulation. There is no particular reason that wind should be treated any differently than the majority of generation resources in Ontario or Canada as a whole. The argument that the contractual approach is always superior to economic regulation simply does not hold for wind in Ontario over the last 20 years. Indeed, economic regulation could do a better job of aligning public costs with public benefits.

> *There is no particular reason that wind should be treated any differently than the majority of generation resources in Ontario or Canada as a whole.*

A third option would be to leverage the larger economies of scale and lower cost of public financing and have new wind projects publicly-owned and operated.

This is already the case of about half of the wind capacity in PEI (PEIEC 2024) and is the thrust of the just-announced strategy in Quebec that aims to roll out 10 GW of new publicly-owned wind by 2035 (Hydro-Québec 2024). For Ontario this would require the lifting of the current policy restriction on OPG that essentially prohibits it from wind generation (MOE 2005). As discussed above, the wind assets would enter OPG's regulated "rate base" and be subject to the lower cost of financing associated with provincially backed Crown corporations, compared to private financing. Another benefit would come from centralized purchasing and other economies of scale that could result in savings of as much as 20 percent (Hydro-Québec 2024).

Conclusion

So complete was its political defeat in 2018 and so few are its current supporters that GEA-like legislation will likely not be implemented again in Ontario for many generations. The GEA allowed for the imposition of third-party sited wind projects over local opposition (WCO 2024) and contributed to a ballooning of electricity prices, which resulted in an unprecedented subsidization of wind and other costs that now total $7.3 billion a year (Ontario 2024a), equivalent to 0.65 percent of GDP (Ontario 2024b). Rates in Ontario recover only 73 percent of system costs. No other government in Canada has subsidized their electricity sector by this much for so long.

Our research shows that costs of wind far exceed its societal and climate benefits for the 2020–23 period, with average net cost of -$124/MWh. Such a negative result is a combination of Ontario's relatively low wind emissions offset (0.227 tCO_2/MWh) and high wind prices ($151/MWh). We also undertook a forward-looking cost-benefit analysis for the 2027–2030 period and calculate an average net cost of wind of -$38/MWh based on a reference price of $80/MWh. The cost-benefit "break-even" wind price for the 2027–2030 period is $46/MWh.

There are financial and structural challenges to align the public costs and benefits of wind generation in Ontario. By design, the public costs were contractually "baked in" in the short and medium term. Despite the current government campaigning on "reviewing" the long-term wind contracts that averaged $151/MWh in 2020–23, once in government it decided not to do so (IESO 2020), but instead increased the size of the subsidies introduced by the previous government in 2017. This means that the government has in effect decided to "wait out" for the high-priced contracts to expire. This report provides a policy framework for the province to assess the price for the re-contracting of those legacy wind projects, and for the procurement of new wind projects.

Structurally, wind's value is relatively low in Ontario's current low-emission nuclear and hydro-dominant grid. Ontario's average wind capacity factor is relatively low. While wind technology could improve this performance in an absolute sense, it will not change the comparative disadvantage, Further, from a seasonal perspective, wind in Ontario is negatively correlated with gas generation, making it relatively inefficient at displacing it. Regardless of the price of wind, these structural short-comings would remain in the short and medium.

The challenge from a policy perspective is to implement programs that are sustainable over time and that align public costs with public benefits. The overall experience of wind generation in Ontario over the last twenty years has been that costs have far exceeded the benefits. Our hope is that this and other research contributions will provide the type of forward-looking guidance to ensure that any future wind development in Ontario is in the public interest. MLI

About the author

Edgardo Sepulveda is a regulatory economist with more than thirty years of experience in the telecommunications and electricity sectors. He has advised governments, regulatory agencies, companies, unions, and consumer advocates in more than forty countries. He has written on electricity issues for the Progressive Economics Forum, the Canadian Centre for Policy Alternatives, and on his Profiles in Decarbonization website, available at: edcarb.org. Born in Chile, Sepulveda is fluent in English and Spanish and has a good working knowledge of French. He received his B.A. (Honours) from the University of British Columbia and his M.A. from Queen's University, both in Economics. He established Sepulveda Consulting Inc. (esepulveda.com) in 2006. MLI

References

Alberta Electricity System Operator (AESO). 2024. "Annual Market Statistics Report." Available at https://public.tableau.com/app/profile/market.analytics/viz/AnnualStatistics_16161854228350/Introduction.

Bahramian, Pejman, Glenn P. Jenkins, and Frank Milne. 2021 "The displacement impacts of wind power electricity generation: Costly lessons from Ontario." *Energy Policy* 151. Available at https://www.sciencedirect.com/science/article/abs/pii/S030142152100080X.

Bishop, Grant, Mariam Ragab, and Blake Shaffer. 2020. *The Price of Power: Comparative Electricity Costs across Provinces.* C.D. Howe Commentary 582. Available at https://www.cdhowe.org/sites/default/files/attachments/research_papers/mixed/Commentary%20582.pdf

Canadian Broadcasting Corporation (CBC). 2002. "Ontario passes power rebate bill." Available at https://www.cbc.ca/news/canada/ontario-passes-power-rebate-bill-1.317384

Cullen, Joseph. 2013. "Measuring the Environmental Benefits of Wind-Generated Electricity." *American Economic Journal: Economic Policy*, 5 (4): 107–33. Available at https://www.aeaweb.org/articles?id=10.1257/pol.5.4.107.

Fell, Harrison, and Jeremiah X. Johnson. 2021. "Regional disparities in emissions reduction and net trade from renewables." *Nature Sustainability* 4, 358–365, 2021 (published December 14, 2020). Available at https://www.nature.com/articles/s41893-020-00652-9.

Financial Accountability Office of Ontario (FAO). 2022. "Ontario's energy and electricity subsidy programs to cost $118 billion over 20 years." Available at https://www.fao-on.org/en/Blog/media/MR-energy-and-electricity-2022.

Government of Canada (Canada). 2018. "Carbon pricing: regulatory framework for the output-based pricing system." Available at https://www.

canada.ca/en/services/environment/weather/climatechange/climate-action/pricing-carbon-pollution/output-based-pricing-system.html.

Government of Canada (Canada). 2021. “Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023–2030.” Available at https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html.

Government of Canada (Canada). 2023. “Social Cost of Greenhouse Gas Estimates – Interim Updated Guidance for the Government of Canada.” Available at https://www.canada.ca/en/environment-climate-change/services/climate-change/science-research-data/social-cost-ghg.html.

Government of Canada (Canada). 2024 (and previous). “National inventory report: greenhouse gas sources and sinks in Canada.” Available at https://publications.gc.ca/site/eng/9.506002/publication.html.

Government of Ontario (Ontario). 2024a. “Expenditure Estimates for the Ministry of Energy (2024–25).” Available at https://www.ontario.ca/page/expenditure-estimates-ministry-energy-2024-25.

Government of Ontario (Ontario). 2024b. “2024 Ontario Budget: Building a Better Ontario.” Available at https://budget.ontario.ca/2024/pdf/2024-ontario-budget-en.pdf

Hydro-Québec. 2024. “Charting the Course toward Collective Success: Wind Power Development Strategy.” Available at https://www.hydroquebec.com/data/a-propos/pdf/wind-power-development-strategy.pdf.

Independent Electricity System Operator (IESO). 2020. “Contract Review Directive Report.” Available at https://www.ieso.ca/-/media/Files/IESO/Document-Library/contract-review/Contract-Review-Directive-Report.pdf

Independent Electricity System Operator (IESO). 2022. “Pathways to Decarbonization.” Available at https://www.ieso.ca/-/media/Files/IESO/Document-Library/gas-phase-out/Pathways-to-Decarbonization.pdf.

Independent Electricity System Operator (IESO). 2024a. “Annual Planning Outlook: Resource Costs and Trends.” Available at https://ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Mar2024/Resource-Costs-and-Trends.pdf.

Independent Electricity System Operator (IESO). 2024b. “Public Reports Data Portal.” Available at http://reports.ieso.ca/public/.

Independent Electricity System Operator of Ontario (IESOO). 2024c. "Supply Mix and Generation." Available at https://www.ieso.ca/Learn/Ontario-Electricity-Grid/Supply-Mix-and-Generation.

Independent Electricity System Operator (IESO). 2024d. "A Progress Report on Contracted Electricity Supply: First Quarter 2024." Available at https://www.ieso.ca/-/media/Files/IESO/Document-Library/contracted-electricity-supply/progress-report-on-contracted-electricity-supply.pdf

Loudermilk, Margaret. 2017. "Renewable Energy Policy and Wind Generation in Ontario." Ivey Business School Policy Brief. Available at https://www.ivey.uwo.ca/media/3775606/january-2017-renewable-energy-policy-and-wind-generation-in-ontario.pdf.

Market Surveillance Panel (MSP). 2023. "State of the Market Report 2022." Available at https://www.oeb.ca/sites/default/files/msp-report-38-state-of-the-market-2022.pdf

McKitrick, Ross, and Tom Adams. 2014. "What Goes Up: Ontario's Soaring Electricity Prices and How to Get Them Down." Fraser Institute. Available at https://www.fraserinstitute.org/sites/default/files/what-goes-up-ontarios-soaring-electricity-prices-and-how-to-get-them-down.pdf.

National Renewable Energy Laboratory (NREL). 2023. "2022 Cost of Wind Energy Review." Available at https://www.nrel.gov/docs/fy24osti/88335.pdf.

New York Independent System Operator (NYISO). 2024 (and previous). "NYCA Renewables 2023." April 22, 2023. Available at https://www.nyiso.com/documents/20142/29609937/2023-NYCA-Renewables-Presentation.pdf/b4b189e8-e213-baf1-9f81-ac425342a2ea.

Novan, Kevin. 2015. "Valuing the Wind: Renewable Energy Policies and Air Pollution Avoided." *American Economic Journal: Economic Policy*, 7 (3): 291–326. Available at https://www.aeaweb.org/articles?id=10.1257/pol.20130268.

Office of the Auditor General of Ontario (AGO). 2011. "Electricity Sector Renewable Energy Initiatives." Available at https://auditor.on.ca/en/content/annualreports/arreports/en11/303en11.pdf

Ontario Energy Board (OEB). 2023 (and previous). "Regulated Price Plan Price Report." (various) Available at https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/regulated-price-plan-rpp

Ontario Ministry of Energy (MOE). 2005. "Memorandum of Agreement with Ontario Power Generation." Available at https://archive.opg.com/pdf_ archive/Regulatory%20Affairs/z5--EB-2013-0321/Exhibit%20A%20-%20Administrative%20Documents/O009_A1-04-01_Attachment%25202.pdf.

Ontario Power Generation (OPG). 2024 (and previous). "2023 Financial Results." Available at https://www.opg.com/documents/2023-financial-results-pdf/

Prince Edward Island Energy Corporation (PEIEC). 2024. "What We Do." Available at http://www.peiec.ca/.

Sepulveda, Edgardo. 2018. "Power to the people: Privatization and electioneering have made electricity prices unbearable in Ontario." *The Monitor*, May 1, 2018. Canadian Centre for Policy Alternatives. Available at https://policyalternatives.ca/publications/monitor/power-people.

Sepulveda, Edgardo. 2022. "Ontario election: The $6.9 billion budget item that (almost) no one is talking about." TVO Today. Available at https://www.tvo.org/article/ontario-election-the-69-billion-budget-item-that-almost-no-one-is-talking-about.

Sorge, Petra. 2024. "German Budget Crisis to Deepen as Renewable Subsidies Double." Bloomberg, May 29, 2024. Available at https://www.bloomberg.com/news/articles/2024-05-29/germany-s-climate-transition-costs-to-spiral-as-subsidies-double.

Statistics Canada. 2024. "Table 18-10-0005-01 Consumer Price Index, annual average, not seasonally adjusted." Available at https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000501

Trebilcock, Michael, and Roy Hrab. 2005. "Electricity Restructuring in Ontario." *The Energy Journal*, Vol. 6, Issue 1. Available at https://journals.sagepub.com/doi/abs/10.5547/ISSN0195-6574-EJ-Vol26-No1-6.

U.S. Department of Energy (DOE). 2023. "Land-Based Wind Market Report: 2023 Edition." August 24, 2023. Available at https://www.energy.gov/eere/wind/articles/land-based-wind-market-report-2023-edition.

U.S. Energy Information Administration (EIA). 2022. "U.S. wind generation falls into regional patterns by season." November 30, 2022. Available at https://www.eia.gov/todayinenergy/detail.php?id=54819.

Wind Concerns Ontario (WCO). 2024. "Municipalities which adopted unwilling host resolutions, effective April 30, 2024." Available at https://www.windconcernsontario.ca/wp-content/uploads/2024/05/Unwilling-Hosts-April-30.pdf

Appendix: Regression methodology

This section provides a summary of the regression methodology and results.

As noted, our regression analysis is based on a well-established economics literature examining the interaction of wind in various grids, including work on the Texas electricity grid (Cullen 2013, Novan 2015), and more recent work analyzing the Ontario grid (Bahramian et al. 2021) and several regions of the United States (Fell and Johnsson 2021).

To take into account seasonal variation, one of the innovations of our regression analysis is that we carry out separate regressions for each week of the year for our study period of 2020–23. To do this we construct a custom database for these four years, based on publicly available data (IESO 2024b). For our database we use the hour as the basic unit of analysis and group all hours in seven-day periods from January 1 of every year, from Week 1 to Week 52. Fifty-two 7-day weeks adds up to 364 days, so we need to add an eighth day to one of the weeks. Each of the weeks from Week 1 to Week 51 have seven days thus a total of 672 hours (24 hours x 7 days x 4 years). Week 52 will get an extra day thus having 768 hours (24 hours x 8 days x 4 years). For analytical purposes we exclude the 24 data points for February 29 of 2020, a leap year.

Our regression analysis is designed to estimate the manner wind generation interacted with the rest of the Ontario grid over the 2020–23 period. Our objective is calculating regression coefficients that quantify whether and by how much wind generation is statistically associated with decreases or increases of other types of generation. In our case, we focus on the three largest generation technologies in Ontario, nuclear, hydro and gas. We also model whether and by how much wind generation increases/decreases net exports (NX) from/to other provinces and the US.

We estimate the following four regression equations for each week **"t"** (from 1 to 52) of the year "**i**", for a total of 208 regressions ("Out" refers to output; "Cap" to capacity) and **"ε"** is the error term:

$$
\begin{aligned}
Out\_Gas_i^t &= \alpha_{10}^t + \alpha_{11}^t\, Out\_Wind_i + \alpha_{12}^t\, Cap\_Gas_i + \alpha_{13}^t\, Cap\_Nuclear_i + \alpha_{14}^t\, Cap\_Hydro_i + \alpha_{15}^t\, Ontario\_Demand_i + \alpha_{16}^t\, External\_Demand_i + \varepsilon_i^t \\
Out\_Hydro_i^t &= \alpha_{20}^t + \alpha_{21}^t\, Out\_Wind_i + \alpha_{22}^t\, Cap\_Gas_i + \alpha_{23}^t\, Cap\_Nuclear_i + \alpha_{24}^t\, Cap\_Hydro_i + \alpha_{24}^t\, Ontario\_Demand_i + \alpha_{26}^t\, External\_Demand_i + \varepsilon_i^t \\
Net\ Exports_i^t &= \alpha_{30}^t + \alpha_{31}^t\, Out\_Wind_i + \alpha_{32}^t\, Cap\_Gas_i + \alpha_{33}^t\, Cap\_Nuclear_i + \alpha_{34}^t\, Cap\_Hydro_i + \alpha_{35}^t\, Ontario\_Demand_i + \alpha_{36}^t\, External\_Demand_i + \varepsilon_i^t \\
Out\_Nuclear_i^t &= \alpha_{40t} + \alpha_{41}^t\, Out\_Wind_i + \alpha_{42}^t\, Cap\_Gas_i + \alpha_{43}^t\, Cap\_Nuclear_i + \alpha_{44}^t\, Cap\_Hydro_i + \alpha_{45}^t\, Ontario\_Demand_i + \alpha_{46}^t\, External\_Demand_i + \varepsilon_i^t
\end{aligned}
$$

Table A1 on page 44 presents the summary regression results by week of year for the wind-coefficients for Gas (α_{11}), Hydro (α_{21}), NX and Gas (α_{31}) and Nuclear (α_{41}). Statistically-significant coefficients are presented by their coefficient results; insignificant results are presented as zero. In this respect we present the significance code for the corresponding level of significance. For the regression as a whole, we present the adjusted R^2. To correct for autocorrelation, we use "Driscoll-Kraay" standard errors. Table A1 also includes the number of observations for each regression, as highlighted above. MLI

TABLE A1: Summary of regression results

		GAS			HYDRO			NET EXPORTS			NUCLEAR		
Obs.	**Week**	**Wind**	**Sign.**	**Adj.R2**	**Wind**	**Sign.**	**Adj.R2**	**Wind**	**Sign.**	**Adj.R2**	**Wind**	**Sign.**	**Adj.R2**
672	**1**	-0.51	***	0.85	-0.29	***	0.78	0.19	***	0.83	0.01	*	1.00
672	**2**	-0.56	***	0.83	-0.27	***	0.75	0.20	***	0.71	0.04	***	0.93
672	**3**	-0.76	***	0.82	-0.10	***	0.71	0.13	***	0.72	0.02	***	0.99
672	**4**	-0.54	***	0.78	-0.22	***	0.70	0.22	***	0.68	0.01	*	0.97
672	**5**	-0.80	***	0.86	-0.12	***	0.75	0.00		0.61	-0.01	***	0.92
672	**6**	-0.69	***	0.76	-0.12	***	0.68	0.17	***	0.68	0.00		0.98
672	**7**	-0.73	***	0.84	-0.10	***	0.56	0.13	***	0.65	0.00		0.98
672	**8**	-0.63	***	0.81	-0.14	***	0.71	0.18	***	0.73	0.01	**	0.99
672	**9**	-0.57	***	0.81	-0.18	***	0.70	0.22	***	0.74	-0.00	+	1.00
672	**10**	-0.55	***	0.73	-0.16	***	0.68	0.20	***	0.79	-0.02	**	0.96
672	**11**	-0.60	***	0.82	-0.15	***	0.59	0.19	***	0.87	-0.02	**	0.97
672	**12**	-0.48	***	0.74	-0.23	***	0.66	0.27	***	0.85	0.00		0.95
672	**13**	-0.49	***	0.71	-0.21	***	0.56	0.27	***	0.87	0.00		0.98
672	**14**	-0.31	***	0.64	-0.36	***	0.62	0.23	***	0.88	0.00		0.99
672	**15**	-0.24	***	0.57	-0.42	***	0.79	0.30	***	0.91	0.01	*	0.96
672	**16**	-0.27	***	0.60	-0.51	***	0.74	0.13	*	0.85	0.00		1.00
672	**17**	-0.39	***	0.79	-0.48	***	0.90	0.05	+	0.92	-0.02	+	0.96
672	**18**	-0.32	***	0.66	-0.57	***	0.87	0.00		0.91	-0.03	*	0.95
672	**19**	-0.53	***	0.82	-0.46	***	0.81	0.00		0.87	-0.01	+	0.99
672	**20**	-0.41	***	0.80	-0.16	***	0.70	0.32	***	0.94	0.00		1.00
672	**21**	-0.40	***	0.79	-0.28	***	0.74	0.15	***	0.90	-0.06	***	0.98
672	**22**	-0.41	***	0.88	-0.34	***	0.67	0.18	***	0.90	0.02	**	0.96
672	**23**	-0.62	***	0.76	-0.36	***	0.32	-0.07	*	0.80	0.00		0.92
672	**24**	-0.58	***	0.85	-0.20	***	0.72	0.13	***	0.90	0.00		0.96
672	**25**	-0.47	***	0.85	-0.33	***	0.75	0.15	***	0.80	0.00		0.93
672	**26**	-0.64	***	0.87	-0.34	***	0.68	0.00		0.71	0.00		0.98
672	**27**	-0.71	***	0.87	-0.34	***	0.82	0.00		0.76	0.00		0.99
672	**28**	-0.52	***	0.81	-0.26	***	0.80	0.07	**	0.55	-0.07	***	0.96
672	**29**	-0.56	***	0.88	-0.23	***	0.79	0.09	*	0.75	-0.01	+	0.99
672	**30**	-0.55	***	0.88	-0.23	***	0.76	0.16	***	0.78	0.00		1.00
672	**31**	-0.57	***	0.85	-0.12	***	0.67	0.23	***	0.70	0.00		0.99
672	**32**	-0.43	***	0.91	-0.27	***	0.79	0.23	***	0.72	0.00		0.97
672	**33**	-0.49	***	0.88	-0.17	***	0.74	0.24	***	0.69	-0.06	**	0.96
672	**34**	-0.78	***	0.91	0.00		0.73	0.16	***	0.82	-0.03	**	0.96
672	**35**	-0.65	***	0.90	-0.15	***	0.69	0.15	***	0.76	0.00		0.95
672	**36**	-0.44	***	0.88	-0.27	***	0.62	0.27	***	0.78	0.00		0.95
672	**37**	-0.65	***	0.82	-0.12	**	0.62	0.17	***	0.74	0.00		0.96
672	**38**	-0.60	***	0.82	-0.27	***	0.71	0.04	+	0.75	0.00		0.98
672	**39**	-0.54	***	0.75	-0.27	***	0.75	0.14	**	0.78	0.02	**	0.98
672	**40**	-0.56	***	0.89	-0.16	***	0.74	0.27	***	0.83	0.00		0.98
672	**41**	-0.58	***	0.87	-0.11	***	0.63	0.25	***	0.88	0.00		0.98
672	**42**	-0.54	***	0.83	-0.17	***	0.71	0.27	***	0.91	-0.01	*	1.00
672	**43**	-0.42	***	0.73	-0.21	***	0.72	0.33	***	0.80	-0.01	***	1.00
672	**44**	-0.56	***	0.84	-0.19	***	0.70	0.22	***	0.76	0.00		1.00
672	**45**	-0.63	***	0.85	-0.17	***	0.68	0.17	***	0.71	0.00		0.98
672	**46**	-0.65	***	0.84	-0.15	***	0.69	0.18	***	0.78	0.01	+	0.99
672	**47**	-0.58	***	0.87	-0.08	***	0.67	0.32	***	0.71	-0.01	**	0.98
672	**48**	-0.58	***	0.92	-0.12	***	0.56	0.26	***	0.76	-0.03	**	0.86
672	**49**	-0.72	***	0.84	-0.17	***	0.56	0.15	***	0.67	-0.01	*	0.95
672	**50**	-0.64	***	0.89	-0.17	***	0.80	0.19	***	0.81	0.00		0.97
672	**51**	-0.83	***	0.86	-0.17	***	0.82	0.00		0.65	-0.02	***	0.98
768	**52**	-0.68	***	0.83	-0.19	***	0.79	0.13	***	0.76	0.01	**	0.99
AVG		**-0.56**		**0.82**	**-0.23**		**0.71**	**0.17**		**0.78**	**-0.01**		**0.97**

Significance Codes: *** = 0.001, ** = 0.010, * = 0.050, + = 0.100

Source: Author's calculations.

> Canada shall be the star towards which all men who love progress and freedom shall come.
>
> – Sir Wilfrid Laurier

Critically acclaimed, award-winning Institute

The **Macdonald-Laurier Institute** focuses on the full range of issues that fall under Ottawa's jurisdiction.

- Winner of the Sir Antony Fisher International Memorial Award (2011)
- Templeton Freedom Award for Special Achievement by a Young Institute (2012)
- Prospect Magazine Award for Best North America Social Think Tank (2018)
- Short-listed for the Templeton Freedom Award (2017)
- Cited by five present and former Canadian Prime Ministers, as well as by David Cameron, then British Prime Minister.
- *Hill Times* says **Brian Lee Crowley** is one of the 100 most influential people in Ottawa.
- *Wall Street Journal*, *Economist*, *Foreign Policy*, *Globe and Mail*, *National Post* and many other leading publications have quoted the Institute's work.

WHERE YOU'VE SEEN US

constructive important forward-thinking excellent high quality insightful timely active

GOOD POLICY
is worth fighting for.

WHAT PEOPLE ARE SAYING ABOUT **MLI**

MLI has been active in the field of indigenous public policy, building a fine tradition of working with indigenous organizations, promoting indigenous thinkers and encouraging innovative, indigenous-led solutions to the challenges of 21st century Canada.

– The Honourable **Jody Wilson-Raybould**

I commend Brian Crowley and the team at **MLI** for your laudable work as one of the leading policy think tanks in our nation's capital. The Institute has distinguished itself as a thoughtful, empirically based and non-partisan contributor to our national public discourse.

– The Right Honourable **Stephen Harper**

May I congratulate **MLI** for a decade of exemplary leadership on national and international issues. Through high-quality research and analysis, **MLI** has made a significant contribution to Canadian public discourse and policy development. With the global resurgence of authoritarianism and illiberal populism, such work is as timely as it is important. I wish you continued success in the years to come.

– The Honourable **Irwin Cotler**

MACDONALD-LAURIER INSTITUTE

MLI
TRUE NORTH
IN CANADIAN PUBLIC POLICY

323 Chapel Street, Suite 300,
Ottawa, Ontario K1N 7Z2
613-482-8327
info@macdonaldlaurier.ca

macdonaldlaurier.ca