CANADIAN INSTITUTE FOR
CLIMATE CHOICES

Technical pathways to aligning Canadian electricity systems with net zero goals

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ABSTRACT

Electricity is a cornerstone of Canada's pathway to net zero emissions. From a national perspective, Canada is well ahead of the global curve in terms of low-emitting electricity. However, the national average masks considerable heterogeneity at the provincial level: 1) low-emitting hydroelectric and nuclear-based provinces (B.C., Manitoba, Quebec, Newfoundland and Labrador, and Ontario) and 2) fossil fuel-based provinces (Alberta, Saskatchewan, New Brunswick, and Nova Scotia). Getting to net zero thus requires a careful look at the challenges and opportunities at the provincial level. This white paper highlights the following five key technology pathways to decarbonizing electricity systems in Canada and discusses policy and economic challenges and takeaways for each: **variable renewable energy**; **clean firm supply**; **transmission**; **enhancing demand flexibility**; and **storage**.

Introduction

On June 29th, 2021, the Canadian Net-Zero Emissions Accountability Act (Bill C-12)[1] received royal assent, becoming law in Canada. This bill defines the transparency and accountability regarding Canada's now-legislated target of achieving net zero emissions by 2050. Electricity will be a cornerstone of getting to net zero for two reasons. First, the generation system must be cleaner, if not entirely non-emitting, to reduce the direct emissions from electricity. Second, more parts of the economy—from transportation, to buildings, to industrial processes, and more—must switch to using electricity as their energy input. This makes the first component—decarbonizing the electricity system—all the more important.

This paper focuses on the first challenge: ***making the electricity system cleaner***. On that front, Canada has a head start against its global peers (Figure 1). Canada's electricity sector has one of the lowest emission intensities worldwide, a legacy of large hydroelectric resources coupled with significant use of nuclear power leading to a relatively clean system… *nationally*.

1 https://parl.ca/DocumentViewer/en/43-2/bill/C-12/first-reading

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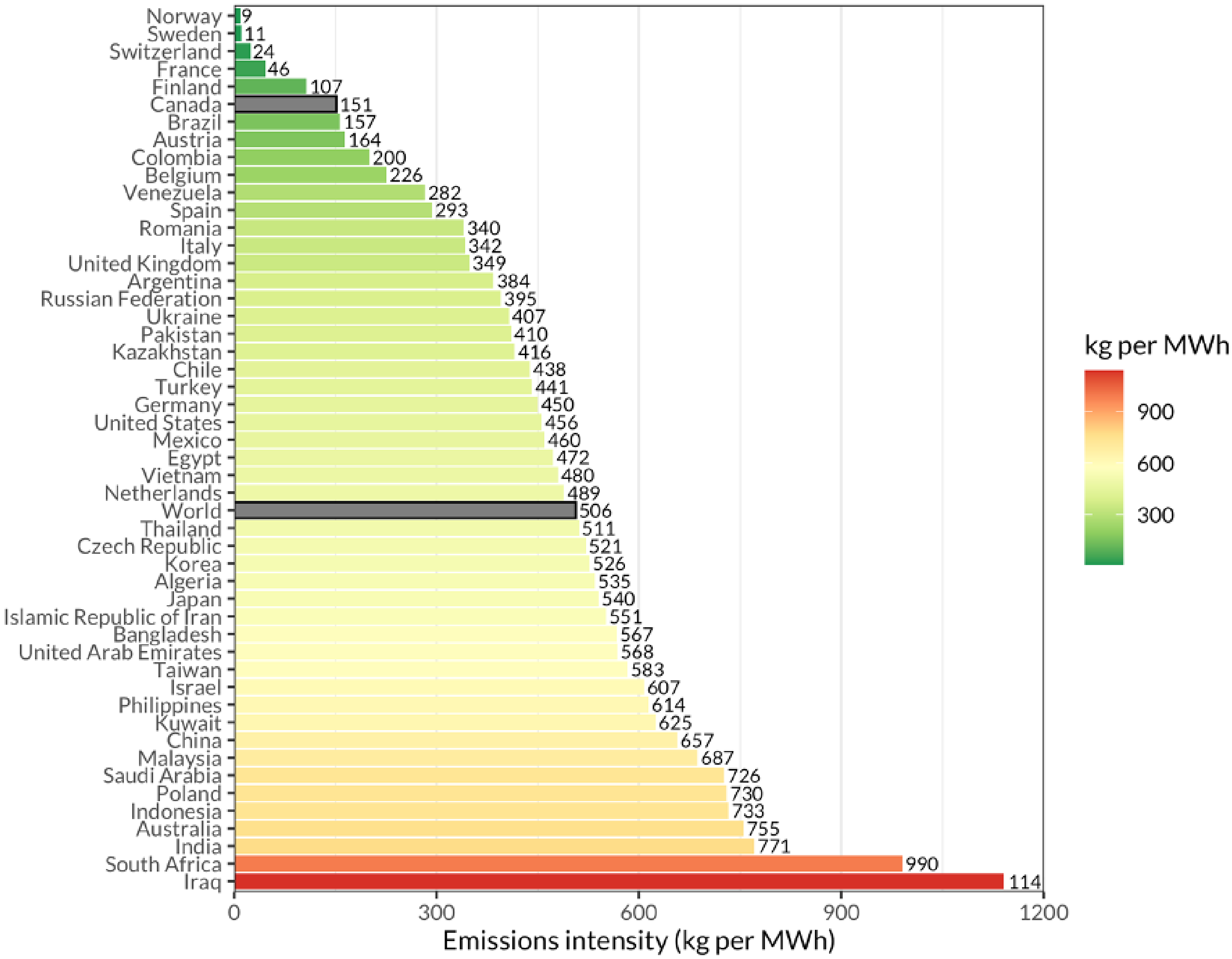
Figure 1

Electricity emissions intensity in top 50 electricity-producing nations

Data for year 2015



Source: International Energy Agency (IEA), 2019
CO2 Emissions from Fuel Combustion Statistics (database)

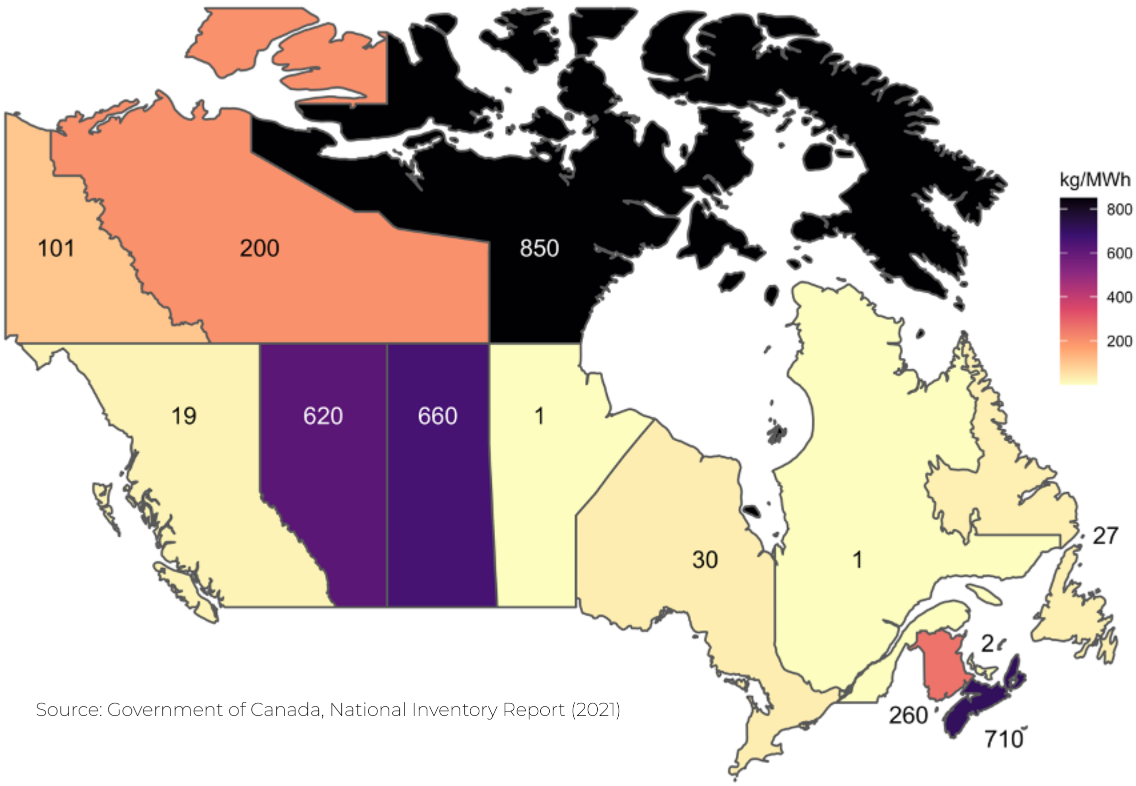
I emphasize *nationally*, however, as averages can be deceptive, and in the case of emission intensities in Canada, this is certainly the case. Taking a closer look at *provincial* emission intensities in Figure 2, we clearly see two groupings of systems. B.C., Manitoba, Quebec, and Newfoundland and Labrador's hydro-dominated systems, along with Ontario's nuclear-dominated system, can all be considered "clean" electricity systems.[2] These systems range from near zero to 2 g/kWh average emission intensity. Alberta, Saskatchewan, Nova Scotia, and, to a lesser degree, New Brunswick all have significant fossil fuel-powered generation resulting in much higher emission intensities, ranging from 290 to 720 g/kWh.[3]

2 I use the term "clean" here in the context of greenhouse (GHG) emissions from electricity generation. All generation involves some amount of lifecycle GHG emissions, as well as other environmental externalities, that are not discussed here.

3 To give these emission intensity values some context, a coal power plant has an emissions intensity of roughly 1,000 g CO_2-eq./kWh, a "peaker" simple-cycle natural gas plant might range anywhere from 500 to 800 g/kWh, and an efficient combined-cycle natural gas plant would be around 350 to 420 g/kWh. To get to clean electricity systems, we need to move down this fossil fuel ladder and ultimately to zero-emitting alternatives.

Figure 2

Canadian regional electricity generation emissions intensities (2019)



Source: Government of Canada, National Inventory Report (2021)

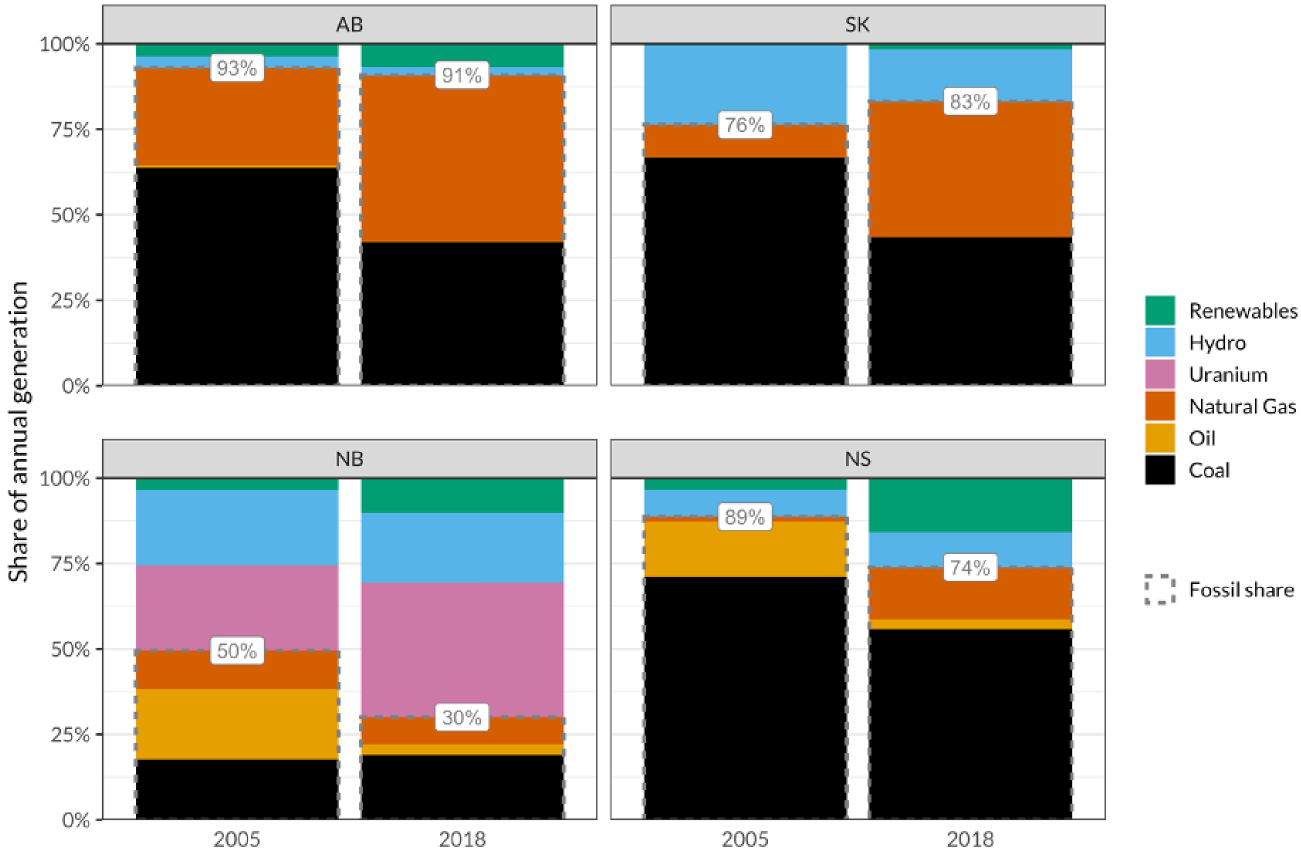
This figure highlights that getting to zero cannot be discussed solely at the national level—a focus on individual provincial impacts, challenges, and opportunities is essential. This paper provides a qualitative discussion of pathways to decarbonize the remaining fossil fuel-based provincial electricity systems, challenges to such pathways, and takeaways for each.

Pathways to decarbonize electricity in the fossil fuel-based provinces

Removing CO_2 emissions from the fossil fuel-generating provinces will be no easy task. In most fossil fuel provinces, the share of domestic supply generated from fossil fuels ranges from 74 per cent (Nova Scotia) to 91 per cent (Alberta). New Brunswick is the outlier, with just 30 per cent generated from fossil fuels (Canadian Energy Regulator, 2020). All of this production will need to be either *replaced* with clean energy alternatives and/or existing generating capacity will need to be *retrofitted* with emissions capture or clean fuel combustion technology options. In addition to replacing existing emitting generation, all provinces will need additional investment in clean generation to serve growing demand.

Figure 3

Share of annual generation (2005 and 2018) for Canada's four "fossil fuel" provinces



Source: Canadian Energy Regulator (CER) Energy Futures 2020; calculations by Author

Looking at Figure 3, the two Maritime provinces have made considerable improvements in removing high-emissions-intensity fuel oil from their systems. Nova Scotia has also made some progress in replacing coal generation with wind power; however, their share of coal remains above 50 per cent (as of 2018).

To the west, Alberta and Saskatchewan remain highly reliant on fossil fuels in their electricity supply mix. Both have improved their emissions intensity due to a shift from coal to natural gas, but decarbonization remains a distant goal. More recently, Alberta has seen dramatic reductions in their coal generation, due to a combination of plant retirements and less frequent use of the remaining coal-fired plants. For 2020, the share of coal-generated power was down to roughly one-quarter of domestic supply (Leach and Shaffer, 2020).

To get to the system needed for net zero will require even larger changes to many of Canada's provincial electricity systems. Here, I outline five pathways. It is important to note that while I use the term "pathways," these are not meant to be mutually exclusive. Rather, and given the scale of the challenge, all five of those pathways will likely be required, to varying degrees. Challenges and takeaways to each are discussed.

1. BUILD MORE **VARIABLE RENEWABLE ENERGY**. A LOT MORE.

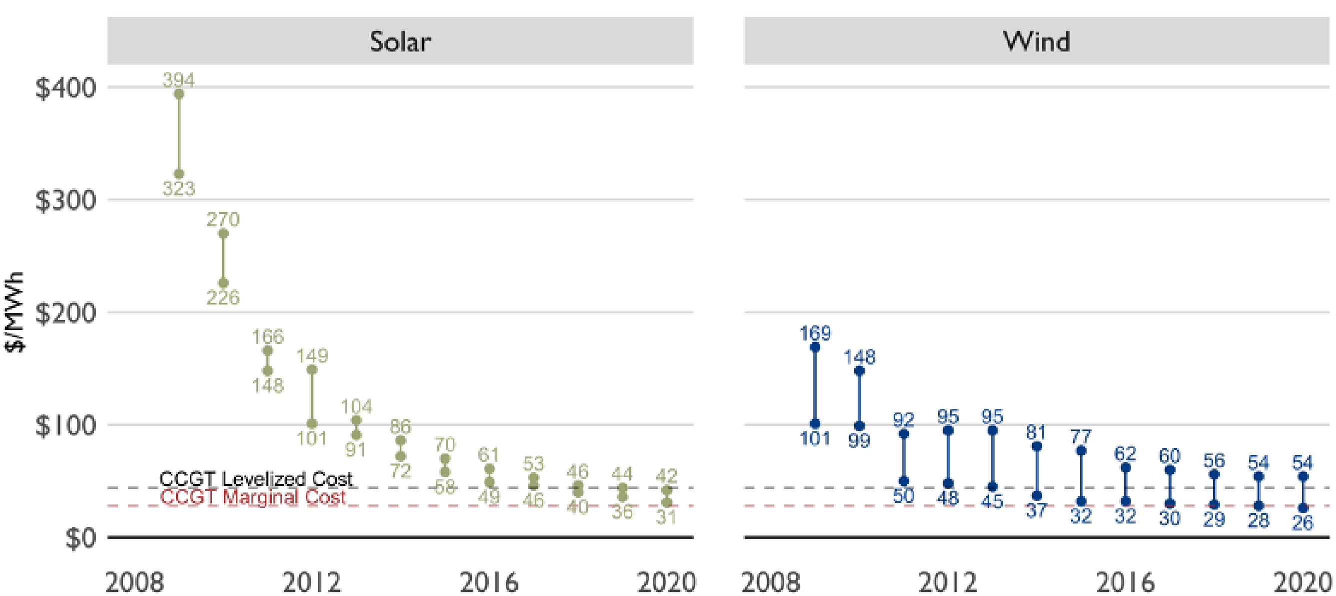
OPPORTUNITY

The CICC report *Canada's Net Zero Future* (Dion et al., 2021) characterized variable renewable energy as a "safe bet." The importance of renewables (i.e., largely wind and solar) is echoed by most reports on net zero pathways in the U.S. as well (Jenkins et al., 2018; Larson et al., 2021; National Academies of Sciences, Engineering, and Medicine, 2021; Williams et al., 2021). The reason for their dominance in terms of generation growth is straightforward: they are now the lowest-cost energy source from a levelized cost perspective (Lazard, 2020). Dramatic declines in the levelized cost of wind and solar over the past ten years have changed the economic conversation around renewables (Figure 3). The levelized cost of these renewable energy sources is now at or below the levelized cost of combined-cycle (efficient) natural gas plants and approaching their marginal cost of running (Schumacher et al., 2020).

Of course, low cost is only half the story. Wind and solar remain intermittent sources of generation and thus lower-value forms of generation than dispatchable generation. However, at the right price, this quality deficiency is worth accepting. With long-term wind contracts now being signed below CAD$30/MWh (3 cents per kWh) and solar below $50/MWh (5 cents per kWh), and with more cost declines expected, renewables are now indisputably a key part of the conversation.

Figure 4

Levelized cost of solar and wind power ($USD)



Source: Lazard 2020, Levelized Cost of Energy Analysis (version 14.0)

CHALLENGES

Despite renewables being deemed a "safe bet," the scale of the required investment presents challenges in its own right. Early renewable development in Canada relied on substantial renewable-specific subsidies. For example, Don Dewees from the University of Toronto estimated Ontario's original feed-in-tariff rates resulted in implicit carbon prices ranging from $169 per tonne for wind to over $1400 per tonne for rooftop solar (Dewees, 2013). Some have argued that this early action, while costly, resulted in a "learning-by-doing" benefit, driving down costs for future adopters due to technological and supply chain improvements. Despite these benefits, the high prices in Ontario's early renewable policies remain hard to justify (Beck et al., 2018).

Fortunately, the economic situation around renewables is much changed. Only a decade ago, Ontario paid prices of $135 per MWh for wind and over $400 per MWh for solar; now contracts are being signed in the low $30s for wind and below $50 for solar in Alberta. While a carbon price is still required to reflect the emission differences, renewable-specific (and often excessive) subsidies are no longer required.

In short, the challenge has morphed from an economic one to a financing one. What do I mean by this?

Given Canada's large and growing carbon price, the value associated with the renewable attributes makes up a considerable portion of the economics of a wind project. Whether this is in the form of monetizable permits or offsets in Alberta's large emitter system or simply the relative cost difference between zero-emission and dirty generation in new electric generation investment under Canada's large emitter system, the importance of the carbon value can't be understated. As a numerical example, at $170 per tonne, the difference in emissions costs between a zero-emission resource and a "best-in-class" natural gas plants is roughly $60 per MWh. This rivals, if not exceeds, the expected energy value from most renewable projects, emphasizing the importance of policy certainty.

As a result, *confidence* in the path of future policy and certainty of revenues plays a large role in renewable investments and access to financing. Resolving this challenge differs depending on whether development occurs in one of Canada's many vertically integrated utility regions or a competitive market, such as Alberta or Ontario. In the former, it is less about financing and more about utilities' integrated resource plans, and ultimately their utility commissions, recognizing the carbon benefits at the level of stated policy stringency (i.e., $170 per tonne by 2030). In competitive generation markets, such as Alberta's, the lack of long-term government contracts and the volatility of energy markets mean developers will increasingly rely on long-term financing supported by corporate power purchase agreements, such as the recent agreement between Greengate Power and Amazon to commit to 400 MW of annual supply from Travers Solar, soon to be Canada's largest solar project.[4] Absent such a contract, the high return on investment investors require to accept the risk around both power prices and environmental attributes means many projects that ought to proceed at reasonable discount rates do not, due to risk.

4 https://www.cbc.ca/news/canada/calgary/alberta-amazon-solar-energy-power-vulcan-travers-1.6077152

To resolve the challenge of long-run uncertainty regarding future Canadian carbon prices, there is a potential role for government as the entity best placed to hold this risk. Creative instruments whereby the government, either directly or through the Canada Infrastructure Bank as its arms-length agent, transfers the risk of policy changes are efficient ways for the government to credibly commit to currently announced stringency. This can take the shape of either contract-for-differences on future carbon prices or policy-contingent financing whereby future repayment amounts are linked to future carbon prices (Beugin and Shaffer, 2021).

TAKEAWAY

The challenge for renewables used to be their high cost and the intermittency of their generation. Technology-driven cost reductions and carbon pricing have solved the former challenge. Today, investment challenges facing renewables are largely a matter of financing and policy uncertainty (i.e., belief over the future price of carbon). Creative instruments to provide policy certainty, discussed above, are now more valuable and cost-effective than renewable-specific subsidies.

From a system perspective, however, we cannot ignore the inherent variability of wind and solar. At low levels of generation, integrating variable renewables is relatively easy and low cost. However, as the share of electricity from renewable sources increases to the levels expected for decarbonization, so too will the challenge. And while this is a problem, it is one with solutions worth investigating and implementing, given the low cost of renewable energy today and expected in the future. The four pathways described below are largely in response to the expected growth in renewables, as ways to integrate them and exploit the benefits of their cheap and clean, but raw, energy.

2. COMPLEMENT RENEWABLES WITH **CLEAN FIRM SUPPLY**

OPPORTUNITY

As mentioned, cheap and clean raw renewable energy is great, but it remains just that: *raw energy*. To get the on-demand power consumers desire will require some amount of "firming" of their variable generation—that is, complementing them with dispatchable forms of power. Thankfully, Canada has a strong starting point in this regard due to plentiful hydroelectric and nuclear resources. A starting point for clean firm supply will be maintaining these resources.

But as Canada adds more intermittent renewables, more "firming" resources will be needed. While I discuss options to integrate renewables using storage, transmission, and more flexible demand in the sections that follow, here I offer a more traditional supply-side approach: managing their variability with clean firm supply.

Clean firm supply options provide two valuable attributes for electricity systems: **clean energy** and **flexibility** in the form of "dispatchable" capacity (i.e. generation capacity that can be turned up and down to meet changing conditions). Different types of clean firm supply offer different mixes of these two attributes.

For example, “peaker” plants, typically simple-cycle combustion turbines run sparingly due to their higher marginal cost are good sources of flexible capacity, but tend to offer very little energy. The low capacity factor of these facilities (defined as the amount they generate over a period relative to what they *could* generate if run 24/7 at their maximum capability) is a feature, not a bug. The idea is to have a supply of potentially high-marginal-cost alternatives at the ready, which Canada is willing to accept due to their sparing use and minimal fixed costs, to back up variable renewable energy (VRE) as needed. The key to getting the economics of such a combination right is a) low cost VRE, b) sufficiently high VRE portfolio capacity factors, and c) relatively low fixed costs of the clean firm “backup” supply.

To make these generation options clean, they need to run off low- or no-emission fuels such as renewable natural gas, biomass, or hydrogen. Retrofitting existing coal and natural gas power generation units to run on hydrogen offers a compelling pathway, especially in the Western fossil fuel provinces. This is due to the relatively low cost of required retrofits, access to an abundance of cheap and clean hydrogen through either “blue” methods (methane reformation with carbon capture) or “green “ones (electrolysis via renewables), and the avoided cost of not having to build much of the related power infrastructure, such as the powerhouse and station interconnections (Neff et al., forthcoming).

Other clean firm supply options are more focussed on providing large amounts of energy, rather than flexibility. Nuclear power, fossil fuels with carbon capture, and geothermal, are all examples of clean firm resources that provide nearly around the clock energy. What these technologies have in common is relatively high fixed costs, lower marginal costs, and high capacity factors, and thus typically a focus on running consistently, rather than flexibly.

Hydroelectric generation straddles both attributes depending on each project’s design and the type of facility. Run of river facilities, for example, are energy providers, with limited, if any, flexibility. Reservoir hydro, however, which is the dominant type of hydroelectricity in Canada, can optimize its water resource into highest value periods of delivery—an excellent example of a flexible and dispatchable resource.

CHALLENGES

Recent research by Dowling et al. (2020) shows that many of the clean firm supply options that focus on around-the-clock energy provision act more as a substitute than a complement to intermittent renewables, with the expansion of firm generators such as nuclear tending to displace wind and solar, while the expansion of wind and solar tending to displace firm generators such as nuclear.

This presents a challenge for designing optimal future systems today, as it pits these pathways against one another to a certain degree. The trade-offs and optimal choice between these two alternatives come down to costs and public acceptability. When renewables were expensive, paying a high cost for their intermittent power *and* having to pay the system cost to integrate them made that pathway a questionable value proposition. Now with recent renewable cost declines, that calculus changes. Renewables plus *something*—be it peaking capacity, storage, flexible demand, or transmission—to integrate them can now compete with the costs of clean firm power.

Meanwhile, the promise of cost declines for next-generation nuclear remains on the horizon, but until we see these deliver, it will remain just that—on the horizon. The varying role of nuclear in future pathways is highlighted in different recent modelling results. The Electrical Power Research Institute's forthcoming *Canadian National Electrification Assessment* using their REGEN model shows a large role for nuclear. This leads to less transmission buildout requirements, as the need for regional integration and renewable variability management decreases. In contrast, the recent NARIS study from Natural Resources Canada and the U.S. National Renewable Energy Lab foresees a lesser role for nuclear and larger role for renewables, in particular wind power. Much of the differences in these two outcomes arises from differences in cost estimates going into the respective models.

Large hydro, while providing both firm power and flexibility, has many ideal characteristics, but the large land footprint and associated deleterious environmental effects, plus recent history of massive cost overruns, have rendered future large hydro projects questionable. Opportunities remain, however, for refurbishments at existing sites, such as adding or upgrading turbines to increase power capacity without additional disturbances. Hydroelectricity will continue to play a central role in providing clean firm—and flexible—supply in Canada. Geothermal holds promise but tends to have geographic limitations, although this isn't entirely true (e.g., Eavor Technologies' closed loop systems).[5]

TAKEAWAY

Supply-side options to integrate variable renewables will be essential. Fully decarbonizing Canada's electricity systems will require clean firm resources to complement growing shares of variable renewable energy. In addition to maintaining and refurbishing existing clean firm power assets, such as Canada's large hydroelectric and nuclear assets, more supply-side resources will be required. Cost and innovation trends along various fronts—from nuclear power to carbon capture to hydrogen for electricity—will play an important role in determining which supply-side options are best suited in future electricity systems.

3. TAKE ADVANTAGE OF REGIONAL COMPLEMENTARITIES WITH **TRANSMISSION**

OPPORTUNITY

In Canada, interprovincial transmission has particular value due to the heterogeneity of provincial electricity systems and resource endowments. Alberta is blessed with among the best wind resources in the country (in terms of capacity factor), Saskatchewan likewise for solar. In contrast, their respective neighbours have an abundance of hydroelectricity and associated reservoir storage. Rather than building solar in cloudy Vancouver or wind in high-cost mountain ridges in B.C., doing so in the Prairies can exploit their cheap raw energy while benefiting from the storage and firming resources of the hydro provinces. Several studies have highlighted the cost-saving

5 Disclosure: Shaffer holds a small investment in the private company Eavor Technologies

benefits of better connecting regions to exploit these regional complementarities (MacDonald et al., 2016; Dolter and Rivers, 2018; Rodriguez-Sarasty et al., 2021; Dimanchev et al., 2021).

Currently there is minimal east–west transmission infrastructure in Canada, for good reason: the country is vast, and opportunities with its much larger trading partner to the south—the United States—are greater. However, the push to decarbonize Canada's electricity changes the game somewhat. Rather than electricity markets driving the push to flow north–south, carbon reduction opportunities in Canada can create as-good or greater opportunities domestically.

CHALLENGES

The challenge to building interprovincial transmission are many.

First, politics can get in the way. Jobs in-province can trump trade-induced savings to consumers because the former provides more visible benefits, whereas even if the latter lead to greater gains for citizens on the whole, the benefits are diffuse. Also, to many, electricity is seen as an essential service, like healthcare and education, for which people want local responsibility and accountability. As seen by B.C.'s self-sufficiency requirement for electric energy, the argument of local jobs and local control can often conflict with the positive economic benefits that come from trade.

Second, regulatory systems and market structure differ significantly from province to province. Case in point: Alberta has an open and competitive generation market with hourly power prices, while B.C. has a government-owned vertically integrated monopoly with no market prices to speak of. Further connecting these regions can lead to an imbalance in opportunities. For example, there is no *market* to which Alberta power generators can sell into B.C. And wheeling through the province to access the U.S. market is often limited by B.C.'s priority claims to transmission for domestic needs. For trade to occur, fair and reciprocal access to opportunities is essential.

Third, as with any linear infrastructure development, projects need to take into account local concerns and identify opportunities to align with broader goals. Challenges such as accessing private property and mitigating local damages from constructing the transmission corridors must be satisfactorily met to develop transmission. In addition, when transmission projects have potential impacts on the rights of Indigenous peoples, they must proceed in a manner that recognizes those rights and advances reconciliation.[6]

TAKEAWAY

Better transmission interconnections between provinces presents as a particularly valuable opportunity in Canada due to the heterogeneity and in many cases complementarity of provincial systems. Connecting fossil fuel provinces (with considerable renewable potential) with hydro-reservoir-rich provinces to optimize their respective energy and capacity comparative advantages can lower the cost of decarbonizing (Dolter and Rivers, 2018).

Getting there will require provincial cooperation and buy-in, as well as considerable federal support to permit and build the required infrastructure.

6 For a thorough and excellent overview of the benefits and challenges of interprovincial trade, see the report *Power without Borders: Moving towards an integrated western grid* by Nick Martin from the Canada West Foundation (2018).

4. GET MORE **FLEXIBILITY FROM DEMAND**

OPPORTUNITY

If the traditional model of system operations is characterized as "*forecast demand and dispatch supply*," the new model, with greater shares of renewables on the grid, will increasingly be "*forecast supply and dispatch demand*." In such a system, there is a lot of value in extracting more flexibility from the timing of demand—i.e., finding and properly incentivizing demand to shift to periods of abundant supply and away from periods of scarcity.

The idea of time-varying scarcity of supply is not unique to electricity markets. When we make a reservation for a restaurant on a Saturday, it is more of a challenge than finding a table on a Wednesday. When we book holidays over Christmas or spring break, flights and hotels are scarce and expensive. In both those situations, either rationing of available supply or price increases are used to clear the market.

When it comes to electricity, however, rationing by cutting off electricity service is not a desirable option. In developed countries, we have come to expect high reliability and availability of power supply. Furthermore, choosing which consumers to ration is not a trivial exercise. When extreme situations warrant such an occurrence, the standard method is random and indiscriminate rolling interruptions of firm load. Instead, using prices allows for a more allocatively efficient distribution of available power by identifying those with greater willingness to pay, versus those with more ability to shift their demand.

Time-varying pricing to reflect scarce or abundant system conditions are the exception, not the norm. In Canada, market prices exist in Alberta, and to a degree in Ontario (though the fidelity of the price signal is dampened due to the hybrid regulated-competitive system that exists in that province). Yet outside some industrial transmission-connected customers, few electricity consumers face the actual prices that reflect real-time system conditions. As a result, consumers are not provided with the proper signal indicating when the system is stressed nor when supply is abundant and therefore don't know when reducing their load is highly valued and when discretionary demand might even be encouraged.

One option to signal the time-varying value of electricity is time-varying tariffs such as time-of-use (TOU) pricing or critical peak pricing (CPP). Ontario has the former and is piloting the latter. Hydro-Quebec is also implementing CPP. With TOU, consumers are able to create habits that can result in lower costs to them by shifting discretionary consumption to lower-price periods. However, from a system perspective there is no guarantee that predetermined price periods coincide with system conditions. Critical peak pricing addresses this critique, as it can be used in a targeted manner when the system is at its most stressed and thus demand reductions are most highly valued. However, CPP does not promote the type of habit-forming behaviour that can result from TOU, nor does it encourage consumption in typically off-peak periods on a regular basis.

Other options to signal the time-varying nature of system conditions include fully dynamic pricing—also known as *real-time pricing (RTP)*—which properly reflects varying marginal system costs but can be too complex for most consumers. Demand charges, in which consumers pay not for the energy they consume over a billing period but for their maximum demand, can be a useful way to encourage less peaky behaviour. When such demand charges are designed to be coincident with peak system conditions, their benefits are increased. Again, however, consumers' ability to properly target reductions in these periods can be limited.

CHALLENGES

A critique of time-varying pricing is that while it can help resolve generation system challenges to varying degrees, it is incapable of coordinating distribution system challenges that arise from too much concentrated local load. An example is if several EV owners on the same city block all plug in their EVs at the same time, 6 p.m., when they get home for work. With the cost of Level 2 home charging at typically 8 kW, such an instantaneous load surge among several houses on the same feeder could overload local distribution equipment. Paradoxically, TOU can make this problem worse in that the start of the overnight off-peak block becomes a coordinating mechanism for EV owners to all set their charging schedule to. This isn't necessarily a challenge for the generation system if their coordinated timing occurs in off-peak periods, but this situation, furthered by a TOU rate, exacerbates the distribution challenge.

There are two major challenges facing the above-described pricing schemes. First is consumer ability to respond in the optimizing manner intended by the schemes design. Pricing systems also suffer from complexity, consumer inattention, and other behavioural realities that weaken their intended effectiveness. Research has shown that consumers often misunderstand complex electricity prices, such that even well-intentioned pricing schemes can lead to worse outcomes (Ito, 2014; Shaffer, 2020). And second, time-varying pricing policies tend to be unpopular, resulting in a reluctance from government-owned utilities to implement them.

As an alternative to pricing mechanisms, direct load control presents as a potential solution. Instead of consumers responding to prices, they would instead be encouraged through discounted plans or one-off payments to give up control over precisely when their EV gets charged. The utility could then sequence all EVs on the block to minimize overlap while ensuring all are charged before some reasonable time in the morning. This engineering-style solution, which can satisfy customer needs with limited customer involvement, is a live area of research today.

Non-pricing options can and should now be part of the discussion. Again, many consumers will have unease with the idea of utilities exerting direct load control over certain appliances in their home or managed charging of their EVs. But to those who are willing, this offers a way to efficiently sequence loads and extract flexibility from consumers, lowering both their private costs and overall system costs.

TAKEAWAY

Getting flexibility from demand has tremendous potential as a relatively untapped resource to assist in the integration of variable renewables. There are reasons to be optimistic that previous reluctance towards this pathway may be set to change. First, variable renewables create the need for more flexibility in demand. When power generation was largely baseload dispatchable power, there was less need to shift demand. Second, technology improvements have lowered the cost of the control and communication infrastructure needed to enable effective demand response. This includes everything from advanced metering infrastructure (“smart meters”) with two-way communication between system operator and customer, to smart thermostats, to smart plugs and automated load-control devices. As a result, customers do not need to consciously respond to price signals but can instead rely on devices that ensure the cost-minimizing response. And third, the pending onslaught of electric vehicles presents as a major new load, one that is far more flexible than, say, heating and cooling, and one where consumers are familiar with seeking fuel cost savings.

5. USE **STORAGE** TO DIRECTLY SOLVE MISMATCHES IN SUPPLY AND DEMAND

OPPORTUNITY

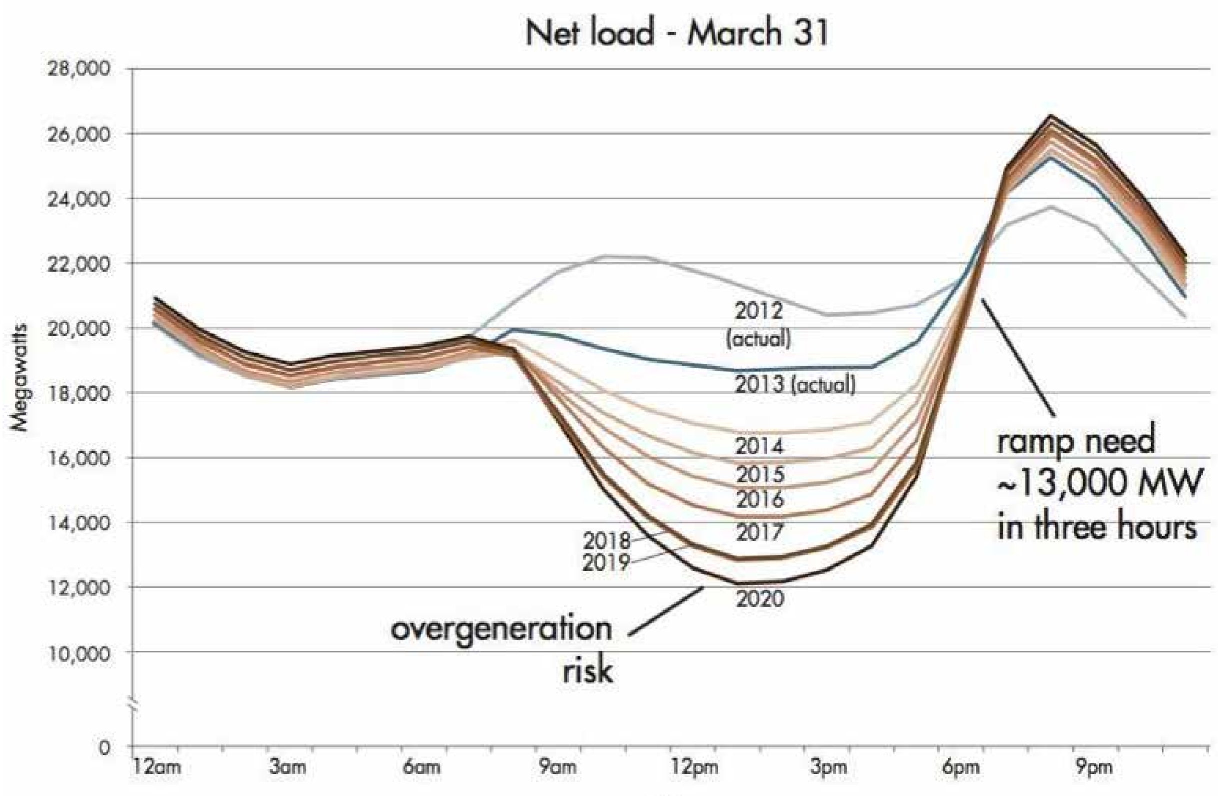
The fundamental challenge with variable renewable resources is that their profile of generation does not necessarily align with the desired profile of demand. Energy storage offers a direct way to shift production into the hours of need. The elegant solution!

The challenge is best illustrated by California’s infamous “duck curve.” The duck-shaped curve (Figure 5) highlights two issues that arise from significant solar generation. First, net load—defined as demand less production from variable renewables—reaches a low point in the middle of the day when load is moderate and solar production is high, resulting in the potential for overgeneration. Second, as the sun sets and demand rises into the evening peak, the ramp up required by dispatchable generation to meet net load gets extremely steep, requiring significant idled and excess capacity capable of quickly coming online.

Batteries are an excellent solution to both challenges highlighted by the duck curve. The ability to absorb excess generation in the middle of the day by charging batteries and then meet the steep evening ramp by discharging batteries only a few hours later is ideally suited to the type of battery technology available today, i.e., relatively short-duration, predominantly lithium-ion technology. Already, batteries can be a cost-effective solution to short-duration needs, largely arising from significant solar generation.

Figure 5

California's "Duck Curve"



(Source: CAISO.com)

CHALLENGES

The types of battery solutions that work well in California face more challenges in Canada.

The first challenge comes from meeting *seasonal variation* in renewable production. In California, this is of lesser concern due to its lower latitude and relatively consistent seasonal profile. In Canada, the northern latitude means typical solar production in the winter can be less than one-third of what is generated in the summer (Figure 6). This adds an additional challenge for solar generation that battery technology is ill-suited to solve.

While batteries will be valuable for managing hour-to-hour and day-to-day intermittency, as well as providing many valuable ancillary services such as frequency regulation,[7] they will not easily resolve this seasonal challenge.

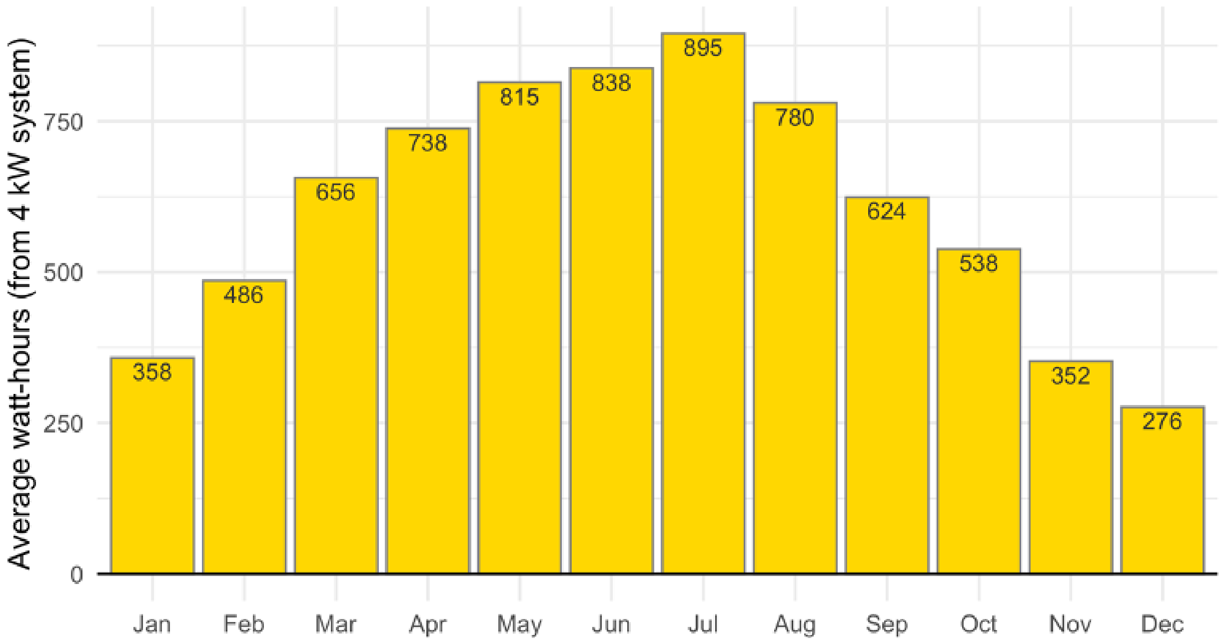
Second, Canada's renewable future will be one that consists of far more wind than solar, again due to the country's natural resources and high latitude, leading to less year-round insolation. Thus the needs that arise from solar power (e.g., shifting power from day to night) are different

7 The electric power system must instantaneously and continuously balance supply and demand. Any gap between generation and load causes the grid frequency to deviate from its standard rate (60 Hz in the United States). Maintaining grid frequency close to its standard rate is crucial to keep the system stable. When there are major deviations in grid frequency, generation and transmission equipment disconnect themselves to avoid damages, and, in the worst case, cascading blackouts can occur as a result. Frequency regulation services are procured by system operators to provide the fast-acting response required to maintain system frequency (Tabari and Shaffer, 2020).

than what is required for wind power. It is not uncommon to have several days in a row of low wind conditions (the Germans even have a word for this: *Dunkelflaute*), and these can often by coincident with peak system conditions, i.e., high pressure systems that bring about extreme cold temperatures and low wind.

Figure 6

Seasonal solar production (modelled) in southern Alberta



Source: Hypothetical production using National Renwable Energy Laboratory (NREL) PVWatts model with location southern Alberta

For both of these reasons, Canada will require longer-duration storage—a much harder nut to crack. Longer-duration storage options include compressed air energy storage, which is a potential solution in Alberta and Saskatchewan, where cavernous geology make this a feasible possibility. Hydro storage is another option, be it pumped or simply reservoir storage. The latter is in abundance in Canada's hydro provinces, emphasizing the importance of the previously mentioned transmission pathway to unlock its potential. Other long-duration solutions face similar challenges as the supply-side solutions: namely that cost and innovation trends need to accelerate to improve their economics.

TAKEAWAY

Storage is often viewed as the solution to the intermittency challenge of renewables. And it does have its cost-effective place, namely short-duration diurnal cycling and ancillary services. For longer-duration needs, which will be more prevalent in Canada, batteries may not be the solution. Other forms of energy storage will be required. Leveraging the existing multi-year storage Canada has in its massive hydro reservoirs is one such option, reiterating the importance of greater transmission connections.

Conclusion

Canada is well positioned to use clean electricity as a cornerstone of its net zero strategy. However, the challenge is not uniform across the provinces, with some already at near-zero emissions from electricity generation, while others—namely Alberta, Saskatchewan, and Nova Scotia—with considerable emissions in their systems.

Wind and solar will undoubtedly play a significant role in decarbonizing these provinces' electricity systems. Their current low cost has improved their economics to the point of making their intermittency worthwhile, even when considering the other system costs of the complementary resources discussed above to integrate their variability. The main challenge for wind and solar investment today is access to financing due to uncertainty over future policy conditions. Creative instruments to de-risk this uncertainty—essentially the government signing for risk of future governments deviating from stated carbon price paths—can provide low-cost solutions to enable massive wind and solar development.

However, other elements of the system will be needed to complement increasing shares of variable generation in order to maintain a reliable system and provide the on-demand power consumers want.

Clean firm supply is already a significant presence in Canada due to large hydro and nuclear resources. The question of additional nuclear will ultimately come down to cost, technical readiness, and public acceptance—if the cost of next-generation (small modular) nuclear comes down, its technical readiness can be demonstrated, and public support is there, it could displace much of the renewable buildout. Further, large-scale hydro-electric developments in Canada are likely to be limited, however, opportunities to repower existing facilities with new or upgraded turbines offer the potential to increase their capacity and flexibility with minimal disturbance and relatively low cost. Other options include geothermal, natural gas with carbon capture, and hydrogen-based power generation. Challenges facing all these are largely around cost and the innovation trends required to get the economics to where they need to be. Research and development policies to move these technologies along their respective learning curves are warranted.

Transmission leverages Canada's existing large reservoir hydro storage assets and regional strengths in wind generation. The challenges with transmission are many—including regulatory and market differences, political challenges associated with gains and losses from trade, Indigenous land rights, and classic NIMBY issues related to building linear infrastructure. Yet if Canada can overcome these challenges, there are significant gains to be had.

Storage has its place, namely multi-hour load shifting and ancillary services, but technologies other than current lithium-ion will be needed for the seasonal and multi-day storage Canada's load profile and wind-dominated renewable portfolio will require. Again, as per the supply-side solutions, challenges in this area largely centre around cost reductions required to enable the development and widespread adoption of new technology.

Lastly, the electricity system of the future can and should involve far more demand-side participation. Variable renewable supply has increased the need for responsive demand; cheap control and communication technology has made it easier to manage demand; and electric vehicles are a new and large load that have made it worthwhile to exert the effort. To fully capture the benefits of responsive demand, customer-facing tariffs need to be redesigned to either incentivize responsiveness or provide bill discounts in exchange for handing over occasional load control.

While challenges remain to decarbonize Canada's electricity system, we remain in an enviable position globally. Leveraging this relatively clean starting position is an opportunity Canada should not ignore.

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