# Data acquisition, processing, strategic analysis for communication products on CNA microsite

Modelling nuclearization of Canada's four "fossil provinces" and the $CO_2$ emission implications

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**Abstract**

We model electric power nuclearization in four Canadian provinces—Nova Scotia, New Brunswick, Saskatchewan, and Alberta—based on those provinces' power generation in 2016 as reported by Environment Canada. In the model, nuclear capacity is added in each province according to (1) that province's total combustible-fired generation in 2016, and (2) currently available Canadian nuclear technology, i.e. the CANDU EC6. In this way, combustible capacity—i.e., baseload capacity—is replaced in successive "waves" each comprising the addition of one EC6 to each province, until each province's combustible output is replaced with nuclear. We model these incremental additions of EC6es over seven such "waves." This sums to fourteen 700-MW machines and a total new nuclear capacity of 9,800 MW across the four provinces. Alberta's new nuclear capacity at this point is 4,900 MW; this is in accordance with that province's intention of adding 5,000 of wind capacity, and is intended to provide a comparison of the $CO_2$ emission reductions from adding wind versus adding nuclear. This is approximately 2,900 MW less than the capacity of the current Ontario nuclear generation fleet. The model indicates that such a nuclearization would eliminate from Canada's national GHG inventory approximately 65 million tons annually from power generation alone. We also model the effect of this nuclearization on $CO_2$ reductions by electrifying gasoline powered motor transport.

# Section 1

# "Fossil province" power generation fuel mixes

## 1.1 Data sources

The data sources are the following.

- Environment Canada National Inventory Report submisssions to the United Nations Framework Convention on Climate Change (UNFCCC).
- Alberta Electricity System Operator (AESO) data page.[1]
- Independent Electricity System Operator (IESO) data page.[2]
- Canadian Energy Issues data page.[3]

### 1.1.1 Fuel mixes 1990–2015

The plots in this section generally follow the Environment Canada "Electricity Intensity" data in terms of fuel category names.

Note that Ontario produced more kWh than the other four "fossil" provinces combined, but less $CO_2$ than any but New Brunswick (Figure 1.1 on page 2). The reason is because Ontario produces most of its electricity by far with "clean" (i.e., non-polluting) sources, whereas in the four fossil provinces polluting sources produce much larger proportions.

Note also that New Brunswick and Ontario are the only provinces where generation on the plot exceeds total $CO_2$.

The 1990–2015 generation fuel mixes of the four fossil provinces, and their breakdown into clean vs polluting fuels, can be seen in Figure 1.2 and Figure 1.3 respectively.

The grid-wide $CO_2$ intensity per kWh (CIPK) resulting from each provincial fuel mix is shown in Figure 1.6.

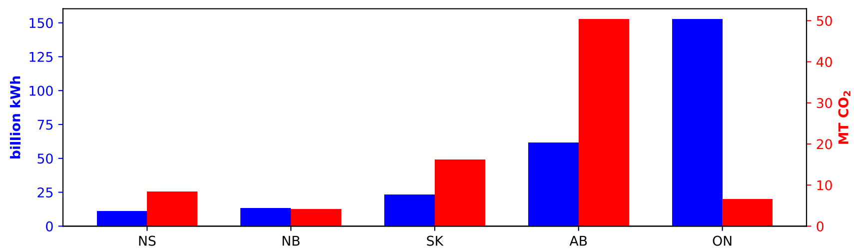


Figure 1.1: Fossil provinces and Ontario, 2015: total generation vs $CO_2$ emissions.

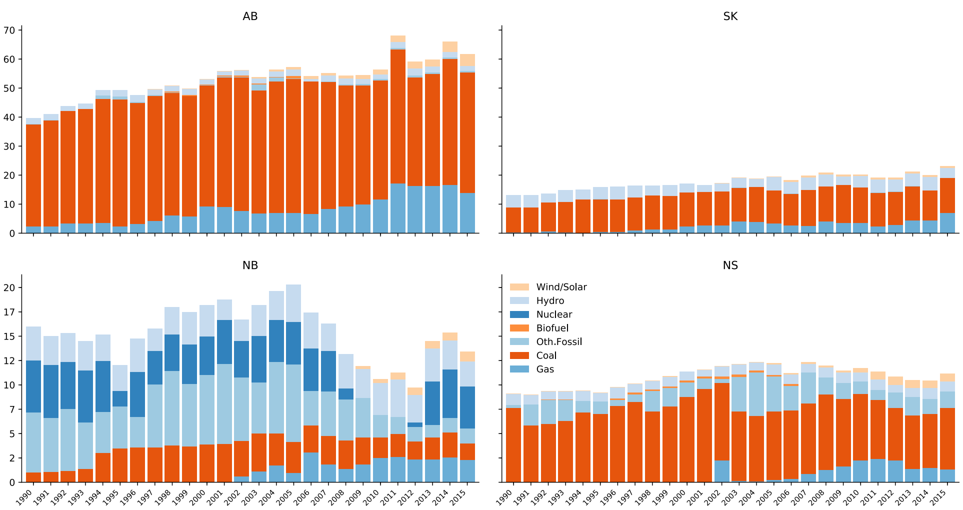


Figure 1.2: Fossil provinces generation 1990–2015, all fuels.

**All fuels**

**Clean v polluting fuels**

### 1.1.2 Fossil provinces $CO_2$ emissions from power generation, 1990–2015

### 1.1.3 CIPK 1990–2015

$CO_2$ Intensity per kilowatt-hour (CIPK) of grid electricity is determined by dividing the estimated $CO_2$ emitted by all the generators feeding a grid over a specified period by their generation in kilowatt-hours over the same period. Knowing CIPK can help compare the relative success of grid jurisdictions in reducing $CO_2$ from power generation. Figure 1.6 shows the CIPK from 1990 to 2015 of the four fossil provinces. As you can see, there are a wide range of CIPKs across the four provinces, from 280 grams (New Brunswick) to 790 grams (Alberta). Contrast these with Germany's grid electricity CIPK, shown in Figure 3.10 on page 21.

[1] http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet
[2] http://reports.ieso.ca/public/GenOutputCapability/
[3] http://canadianenergyissues.com/data/nyOnAb.json

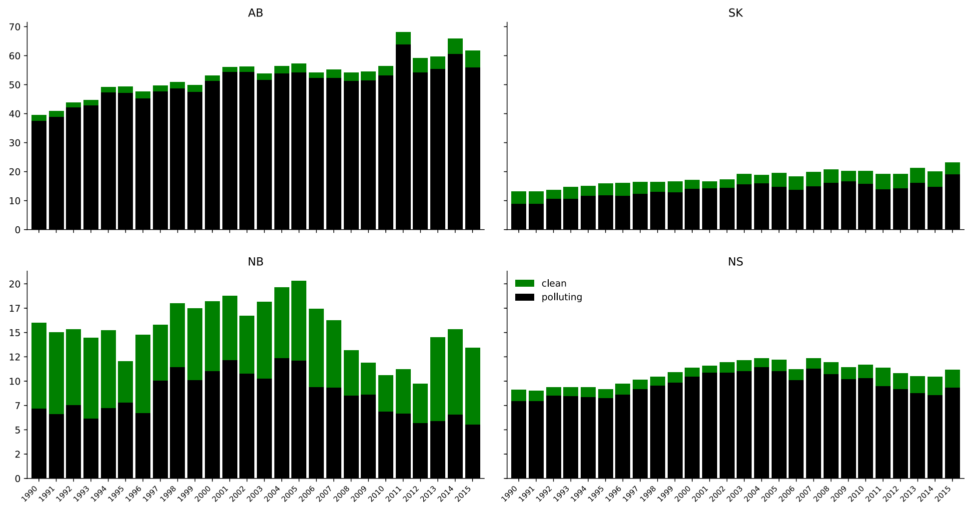


Figure 1.3: Fossil provinces 1990–2015, clean vs polluting generation billion kWh.

Electricity CIPK is of vital importance in electrifying transportation. Currently almost all personal motor vehicle transportatjon in Canada is gasoline- or diesel-powered. Efforts to electrify personal motor vehicle transportation will have less of an effect—and move the electrifying jurisdiction more slowly toward GHG reduction targets—the higher the CIPK of the grid electricity with which electric vehicle batteries are rechargeed.

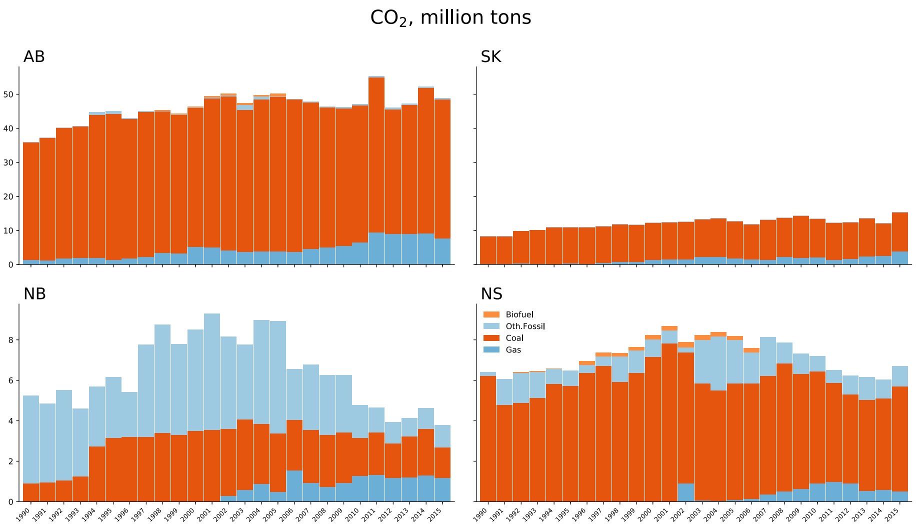


Figure 1.4: Fossil provinces $CO_2$ emissions from electricity generation, by fuel, 1990–2015.

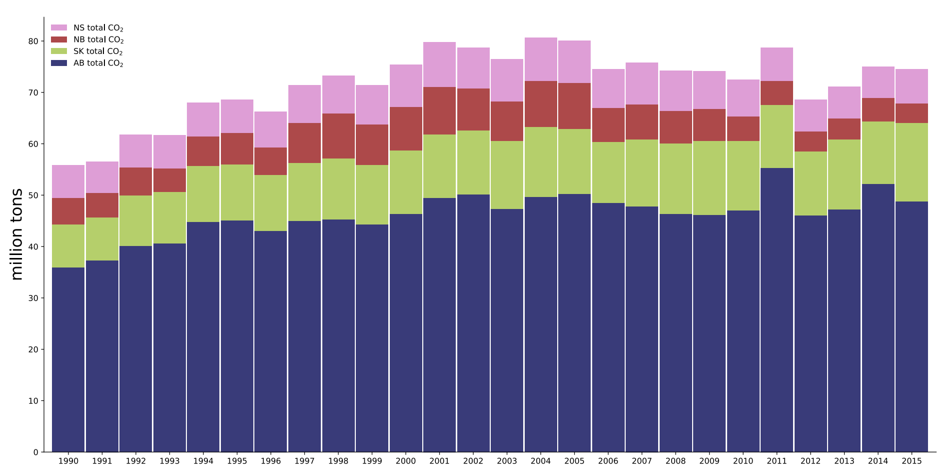


Figure 1.5: Fossil provinces total $CO_2$ emissions from electricity generation, by year, 1990–2015.


Figure 1.6: Fossil provinces CIPK, 1990–2015.

# Section 2

# Replace polluting baseload with nuclear

## 2.1 Introduction

### 2.1.1 Incremental addition of one EC6

The models in this section are premised on nuclear being the most effective way to reduce $CO_2$ as rapidly as possible from the power generation sectors of the four fossil provinces.

This assumes the following.

- Each "wave" occurs across all four fossil provinces, at the same time.
- When a province's polluting generation has been replaced with EC6 output, nuclearization is complete in that province, and no more nuclear capacity is added in subsequent waves.

While completely replacing combustible generation across the four provinces would require something on the order of 11,400 MW of nuclear capacity (see Figure 2.1), it may be useful to envision adding reactors in "waves," each wave involving adding a single EC6 to each province. Seven such waves, and the $CO_2$ emission reductions each wave would produce in each province, are shown in Figure 2.2.

The total $CO_2$ reduction of each wave is shown in Figure 2.3.

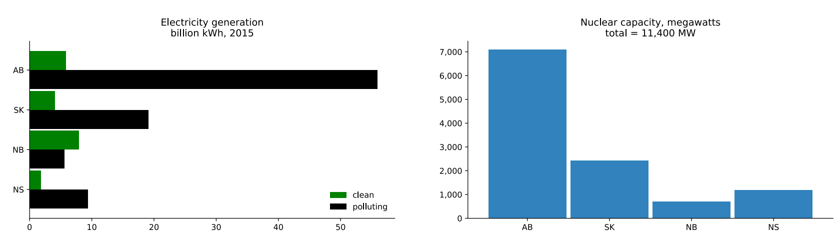


Figure 2.1: 2015 clean vs polluting generation, and nuclear capacity required to replace polluting.

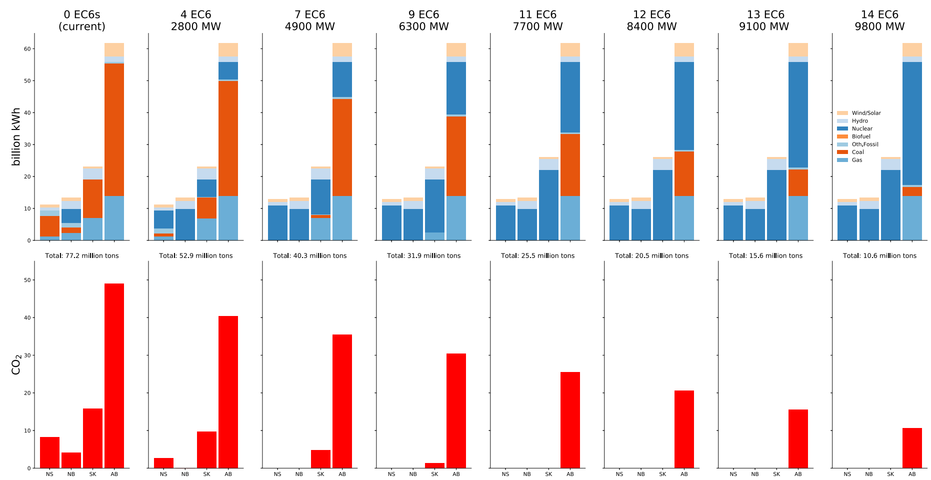


Figure 2.2: Effect of nuclearizing fossil provinces.

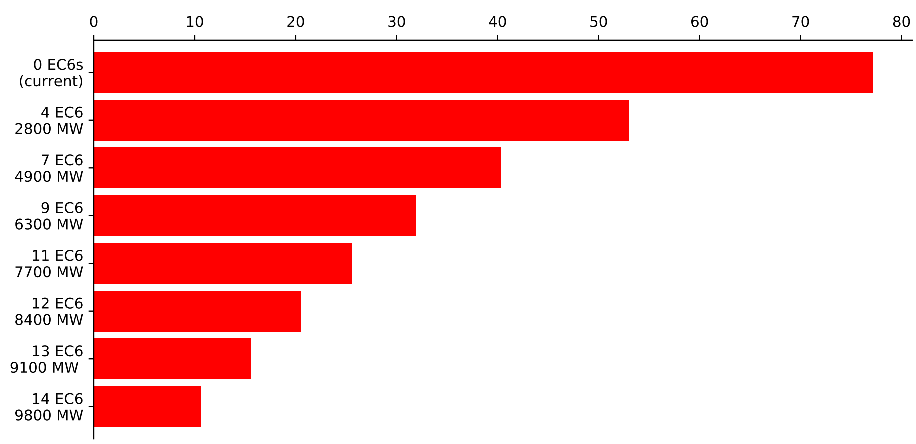


Figure 2.3: Total $CO_2$ emissions after nuclearizing fossil provinces, various levels of nuclearization, million tons.

### 2.1.2 Focus: Alberta

Of the four fossil provinces, Alberta generates by far the most electricity and uses by far the most polluting fuel to do so. Because of the preponderance of polluting fueled generation in the provincial mix (see Figure 1.3 on page 3), it is plain that Alberta requires the greatest electricity decarbonization measures of the four provinces. In the final four nuclearization waves shown in Figure 2.2, the only province still being nuclearized is Alberta, and after the final wave that province still generates a significant amount (close to 20 billion kWh per year) of electricity with polluting fuels.

It is Alberta's current intent to decarbonize electricity by phasing out coal and replacing coal generation with wind.[1] We have modeled such a decarbonization, comparing current generation on a day chosen at random (March 22, 2018) both with the intended 5,000 MW of wind and with scenario in which decarbonization is achieved with 5,000 MW of nuclear instead of wind.

In the "Wind = 5,000MW" and "Nuclear = 5,000MW" scenarios, first coal, then combined cycle gas, then cogeneration gas are displaced by the zero-emitting generation. Coal is displaced first, because the intent is to phase coal out of the mix. When all coal is displaced, combined cycle gas is displaced next. This is because combined cycle is the least flexible of the remaining gas generation; therefore flexible gas must remain to ensure grid stability.

The results of the Alberta-focused model are plotted in Figure 2.4. Table 2.1 compares the summary $CO_2$ emission statistics and sums of the three generation scenarios.

As you can see, on March 22 2018, wind output was not particularly high in Alberta. As a result wind output does not displace much coal output, and consequently $CO_2$ emissions are not significantly reduced compared with the actual (business-as-usual) scenario.

However, in the "Nuclear=5000MW" scenario, $CO_2$ emissions are significantly reduced—from over 151,000 tons to less than 61,000. All coal, and nearly all combined cycle gas, is displaced.

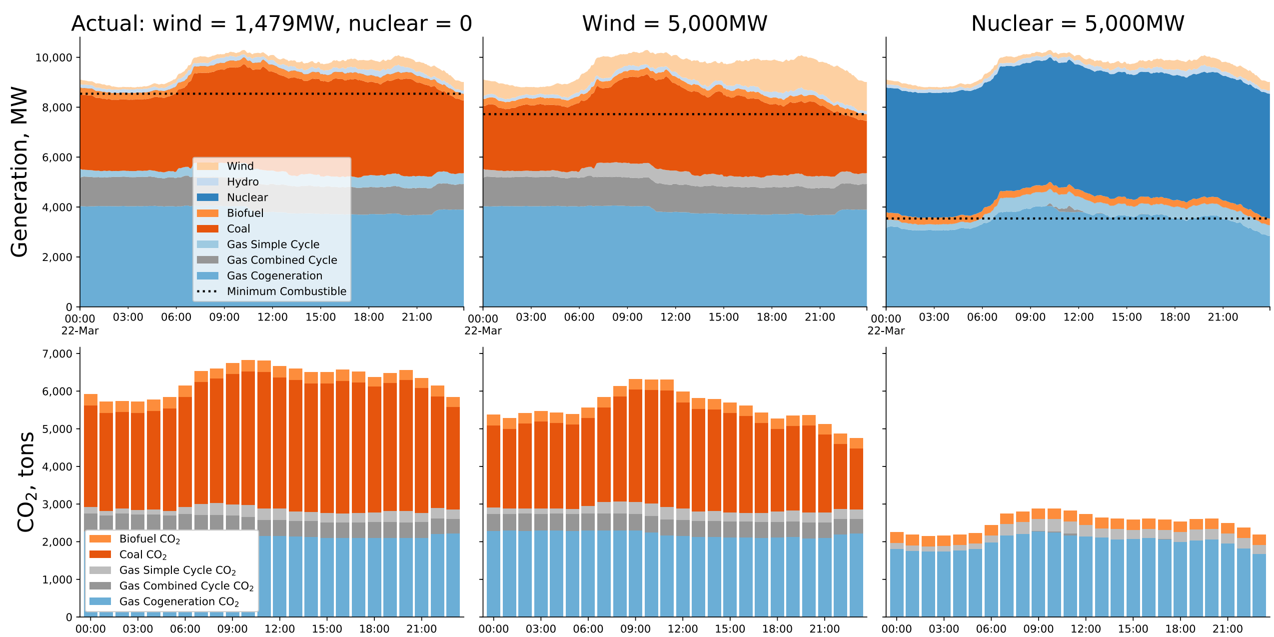


Figure 2.4: Alberta generation and $CO_2$ emissions: wind vs nuclear, March 22 2018.

### 2.1.3 Nuclearizing power generation in the Territories and provincial remote communities

Most of Canada's territories and remote communities are served with electricity that is generated with fossil fuel, most of which is diesel. These communities are not only subject to fluctuating prices

[1] See Alberta Rnewable Electricity Program website: https://www.alberta.ca/renewable-electricity-program.aspx

Table 2.1: Alberta, March 22 2018: $CO_2$ emissions under the three scenarios, tons

| | Actual | Wind=5,000MW | Nuclear=5,000MW |
|---|---|---|---|
| *mean* | 6,311 | 5,579 | 2,514 |
| *std* | 377 | 422 | 244 |
| *min* | 5,723 | 4,757 | 2,155 |
| *25%* | 5,897 | 5,356 | 2,251 |
| *50%* | 6,491 | 5,447 | 2,589 |
| *75%* | 6,575 | 5,818 | 2,664 |
| *max* | 6,823 | 6,319 | 2,884 |
| *sum* | 151,474 | 133,899 | 60,347 |

due to the vagaries of the international market for diesel, but their electricity systems are highly emitting as well. Territorial combustible electricity and generation in 2015 was as follows:

- Northwest Territories: 157 million kWh.
- Nunavut: 157 million kWh.
- Yukon: 25.5 million kWh.

Nunavut is alone among the three territories in that all its electrical power generation is with fossil fuel. Moreover, its 25 permanent settlements represent 25 distinct and separate power systems. Nunavut's total generation in 2015 was 157 million kWh.[2] Dividing that amount among Nunavut's 25 permanent settlements gives a range of 707,000 annual kWh (Grise Fjord) to 32.1 million kWh (Iqaluit).

This in turn suggests that average generating capacity in Nunavut permanent settlements ranges from minimum of 90 kW to a maximum of 4 megawatts for Grise Fjord and Iqaluit respectively.

Currently the smallest of the "very small" reactor designs reported by the World Nuclear Association[3] is roughly 3 megawatts. This indicates that only Iqaluit (4 megawatts) and, depending on the meaning of "a few MWe" in the WNA report on small reactor designs, possibly the next four largest settlements (Arviat, Rankin Inlet, Baker Lake, and Igloolik; see Firuge 2.5) are suitable candidates for these very small reactor designs.

Therefore, completely nuclearizing electricity generation in Nunavut may feasible only in the five largest settlements. On this basis, we could estimate that it is feasible to remove ~54 tons from Nunavut's electricity generation $CO_2$ inventory—that is the sum of $CO_2$ emissions from the five largest settlements.

[2] See Canada's NIR 2017, part 3, p. 106.

[3] see http://www.world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/small-nuclear-power-reactors.aspx

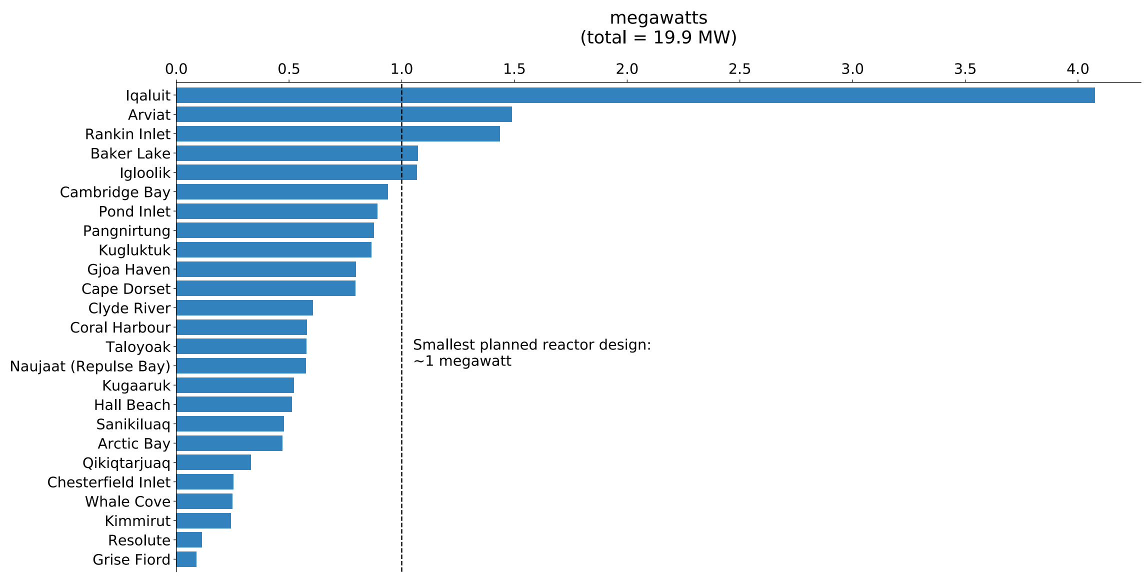


Figure 2.5: Nuclear capacity to replace Nunavut combustible generation, by permanent settlement

# Section 3

# $CO_2$ reductions, cost of Renewable Energy

## 3.1 Introduction

Two components of cost must be considered in the case of all electricity: the cost of generation, and the cost of delivery. Generation cost in some jurisdictions is much easier to determine. Ontario is one such jurisdiction. Approximate costs, as a function of the dollar rates paid to generating entities per kilowatt-hour of electrical energy provided, are a matter of public record. Figure 3.1 shows the average costs of the major generation fuel types in Ontario.

Delivery costs[1] are more difficult to quantify, and are not covered in this report. However, one point is worth bearing in mind. Delivery costs in the case of intermittent, non-dispatchable renewable energy (wind and solar) could be fairly reckoned to be a function of the generation capacity factor of these sources. Like generation costs (see the next section), delivery costs of intermittent non-dispatchable renewable energy are inversely related to their respective capacity factors. Hence, because of their non-dispatchability and relatively low capacity factors (approximately 30 percent in the case of wind, 15–20 percent in the case of solar), delivery costs are higher per kWh delivered for wind and solar than those for dispatchable and baseload sources.

### 3.1.1 Empirical evidence from selected jurisdictions

The per-kilowatthour cost of RE shares an inverse relationship with its capacity factor: the lower the CF, the higher the per-kWh cost. Hence, solar (in Ontario, CF ~15 percent) tends to be the most expensive (in Ontario, average ~49 cents per kWh), followed by wind (in Ontario, CF ~33 percent, cost ~13 cents).

The intermittent character of wind and solar imposes other costs as well. Intermittency of wind and solar increases the importance of other generation types that are dispatchable. The more wind and solar are added to a grid, the greater the requirement for dispatchable sources that can provide voltage stability and ensure that the grid frequency is held within the required parameters, and other services. Because wind and solar typically receive dispatch priority on the grid,[2] the unit

[1] Delivery costs are themselves made up of components. The two main components are transmission (i.e., the physical infrastructure required for putting the generated energy into a grid) and quality of power (voltage and frequency).

[2] In spite of the low annual capacity factors of wind and solar, grid dispatch rules are typically waived so as to give them dispatch priority. This waiving of normal rules reflects desire on the part of most jurisidictions to meet mandated renewable energy targets. The low CFs of wind and solar make it necessary that they receive priority dispatch—together with some combination of higher-than-average per-kWh rates, or tax credits and other publicly

energy generation costs of the dispatchable "stand in" generation are pushed upward. These costs are typically covered through some sort of revenue mechanism such as capacity payments. This is an effect of adding significant amounts of renewable energy.

In Ontario, the generation type most affected by intermittent renewables is natural gas. (This is also the generation type that renewables are meant to displace.) Hence, though gas commodity prices have been low over the past decade, the cost of Ontario natural gas–fired generation has been on average 15–16 cents per kWh (Figure 3.1)—more than double the rate for nuclear energy and triple that of hydro. These prices are necessary to maintain the fleet of gas-fired generators, the importance of which is increased, paradoxically, the more renewable energy is added.

The "must take" rules for wind and solar do not affect only natural gas–fired generation. They affect, and impose costs on, non-polluting generation as well. In Ontario, these other types are nuclear and hydro. Both nuclear and hydro are much less expensive per-kWh than wind and solar (see again Figure 3.1). Thus, during periods of surplus baseload, hydro and rampable nuclear (the Bruce station) are curtailed in favour of wind and solar, even though the latter are far more expensive and there is nothing to be gained, emissions-wise, by preferring one type over the other.[3]

**Ontario**

Figure 3.1 shows the general per-kilowatt-hour cost of each major type of generation in Ontario. The "Hourly cost" plot in Figure 3.4 shows how these costs were applied on May 28–June 4 2018. As you can see, the proportions of costs of each major fuel type are much different from each fuel's generation (the "MWh generated" plot). For example, solar's contribution to cost (right-hand plot in Figure 3.4), is much greater than its contribution to the energy generated (left-hand plot). Figure 3.1 shows why. Solar is by far the most expensive way to produce electricity in Ontario. Its average contracted cost is roughly 49 cents per kWh. Mean cost of all energy in the grid is typically in the 7–8 cents per kWh range, meaning that solar typically costs 6–7 times the mean cost of generation.

This tends to produce hourly CIPK and overall costs per kWh (Figure 3.5) that are confusing when we try to understand the pricing rationale. We note that cost is highest during on-peak hours, which is what we would expect. However, the driver of the elevated on-peak cost is solar, which makes up by far the greater of the two main fuels—gas and solar—whose highest production tends to occur during peak hours. We would expect the increased cost during on-peak hours to reflect increased use of fossil fuels and hence a higher CIPK during those times. While CIPK is indeed higher during peak hours, the impact of solar is evident (see Figure 3.2). In the case of Ontario, generation costs increase during peak hours because there tends to be a significant amount of solar generation in the system at those times.

Though it makes no difference, from the perspective of climate change, what time of day a ton of $CO_2$ is emitted into the atmosphere,[4] Ontario ratepayers pay a far greater price for zero-$CO_2$ solar power—i.e. they pay a far greater price to not emit $CO_2$ during peak hours—than they pay to not emit $CO_2$ during off-peak hours (see Figure 3.3). The disparity exists simply because of the inherent physical and hence economic characteristics of the generation type Ontario has chosen to be most prevalent during peak periods. Solar's capacity factor is low, hence its price is high. Its greatest production is during summer peak periods. Therefore, it drives up overall peak prices.

funded incentives—so as to ensure economic viability of the entities that run wind and solar generation intallations. While tax credits and other publicly funded incentives may not be reflected in the per-kWh rate at which customers are billed at the retail level, they still comprise a significant portion of the actual cost of electricity.

[3] In 2013 the rules were changed so as to avoid curtailing nuclear in favour of wind in SBG periods. To a degree, wind is now curtailed first in these situations, but wind producers still receive the same revenue as they would have if they were not curtailed. Solar is not curtailed at all.

[4] $CO_2$'s residence time in the atmosphere is measured in many hundreds, even thousands of years. See Susan Solomon "Irreversible climate change due to carbon dioxide emissions," *Proceedings of the National Academy of Sciences of the United States of America*, February 10, 2009, p. 1705. http://www.pnas.org/content/106/6/1704

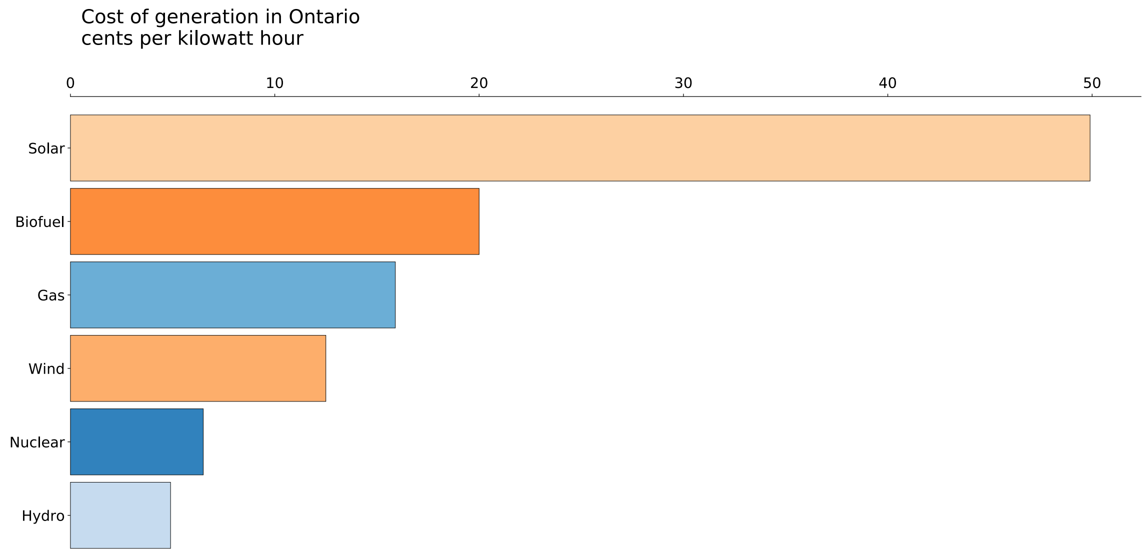


Figure 3.1: Ontario average contracted and regulated cost of generation by fuel type

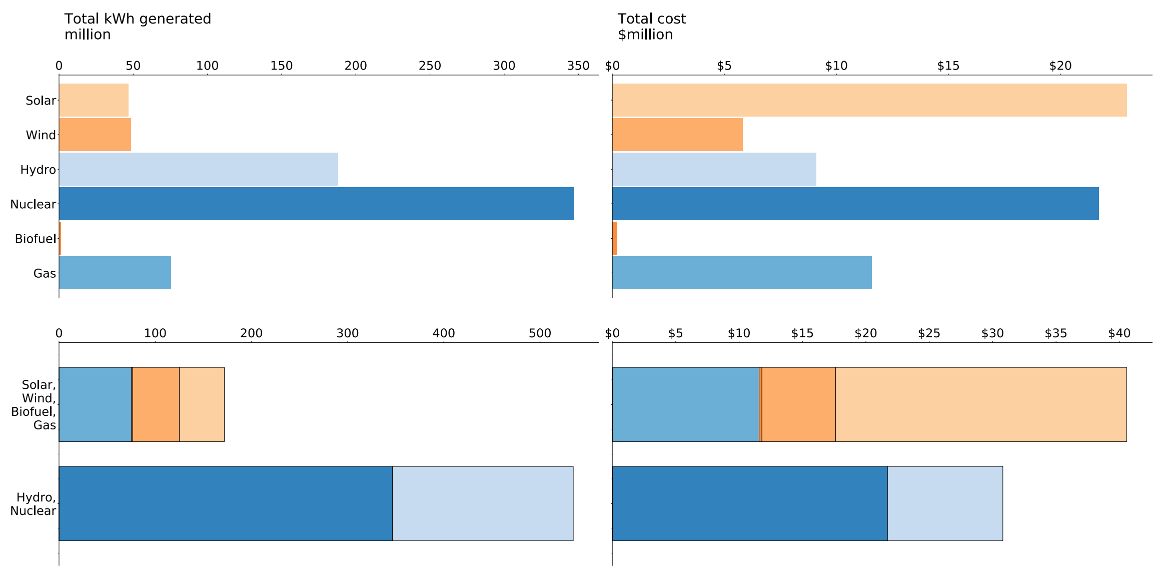


Figure 3.2: Ontario on-peak total generation and cost, by fuel type, May 28–June 4 2018. In the summer period (May 1 to October 31), on-peak time is 11 am to 5 pm; mid-peak is 7 am to 11 am and 5 pm to 7 pm; off-peak is 7 pm to 7 am and all day on weekends and holidays.

Moreover, the time-of-use pricing has no effect on final electricity costs. Even if ratepayers were to completely succeed in shifting their electricity use to off-peak hours, they would still be liable for the amounts owing for solar generation, the vast bulk of which occurs during on-peak hours.

This in turn suggests that time-of-use retail pricing of electricity serves more as a cost-recovery mechanism than as an incentive for ratepayers to curtail usage during peak times. It does not matter whether ratepayers are successful in their efforts to curtail peak usage. As is suggested in Figure 3.5, the time-of-use rates appear designed so as to maximize revenue flow to generators in order

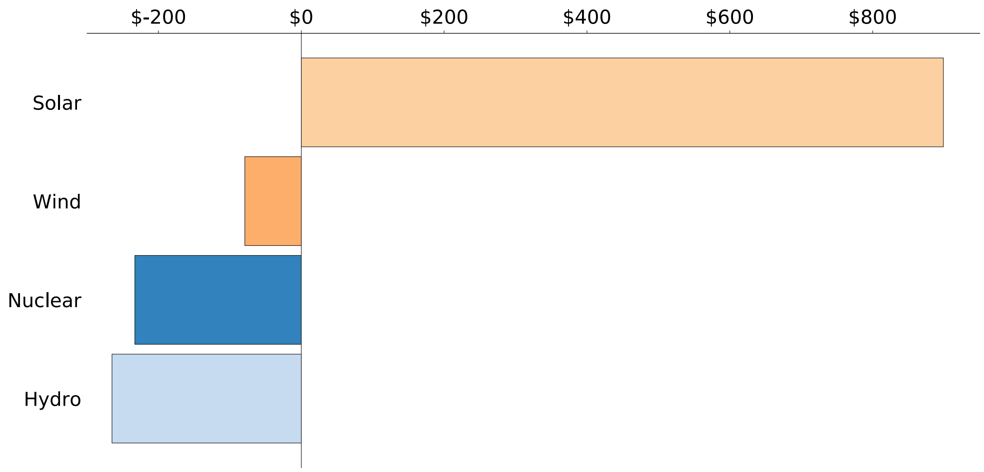


Figure 3.3: Ontario per-ton cost of $CO_2$ avoidance, by generation type. Reference polluting fuel is natural gas: CIPK = 378 grams, cost = 15.9 cents.

to guarantee that as much as possible of the amounts owing at the contracted rates are paid for electrical output during the period in which the cost is incurred.[5]

### Germany

Few countries have adopted renewable energy as strongly as Germany. Since the turn of the century Germany has, through various politically supported mechanisms including and especially the Feed-In Tariff (FIT), installed 52,000 megawatts of onshore wind and over 43,000 megawatts of solar photovoltaic. Wind capacity increased thirteenfold during the period 2000–2015 (see Figure 3.7).

Onshore wind alone now represents roughly 25 percent of Germany's installed electricity generating capacity.

Figure 3.7 shows each generation fuel's position in the German generation fuel mix, in terms of its absolute energy contribution (left column) and as a percentage of the total energy of all fuels (right column). As you can see, output of the major fossil fuels coal and gas was roughly constant over 1996–2015. Nuclear was roughly constant in 1996–2010, then declined by roughly 50 billion kWh annually after 2010, reflecting the halving of available capacity following March 2011 as part of Germany's official intent to phase it out.

The only significant increases were with Biofuel/Waste, and the "new" renewables Wind/Solar, Geothermal, and Other (tidal).

[5] The time-of-use rates shown in the right-hand plot in Figure 3.5 are not adequate, when applied to the bills of Class B Global Adjustment customers in Ontario, to recover all the costs of generation. Up to mid-2017, time-of-use rates could fairly be regarded as representing the cost of electricity to Class B Global Adjustment customers, who represent the vast majority of electricity customers but account for a smaller proportion of electricity consumed. Time-of-use rates under the Fair Hydro Plan implemented in July 2017 were 21–26 percent less than those in 2015. The shortfall is now being paid to generators through borrowing. While this has the effect of lowering electricity bills today, it does not change the cost of electricity at all—generators will continue to be paid according to same average rate for their class as shown in Figure 3.1. Rather, the FHP simply defers ratepayers' payment of the above-mentioned shortfall to a later date, adds a borrowing cost (interest), and temporarily shifts the method of payment to taxes instead of electricity bills.

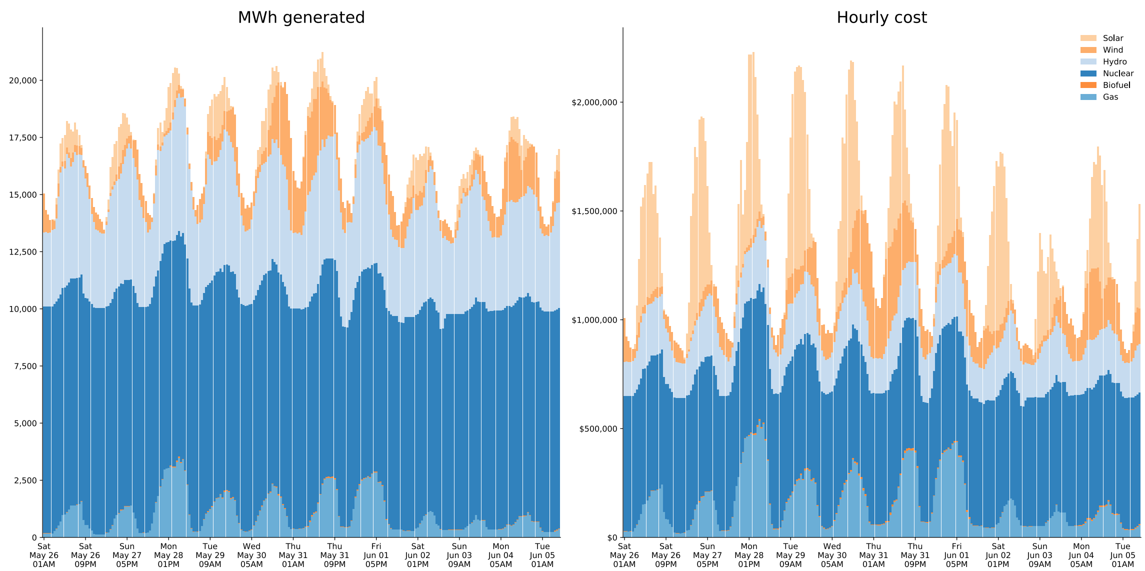


Figure 3.4: Ontario hourly generation and cost, May 28–June 4 2018.

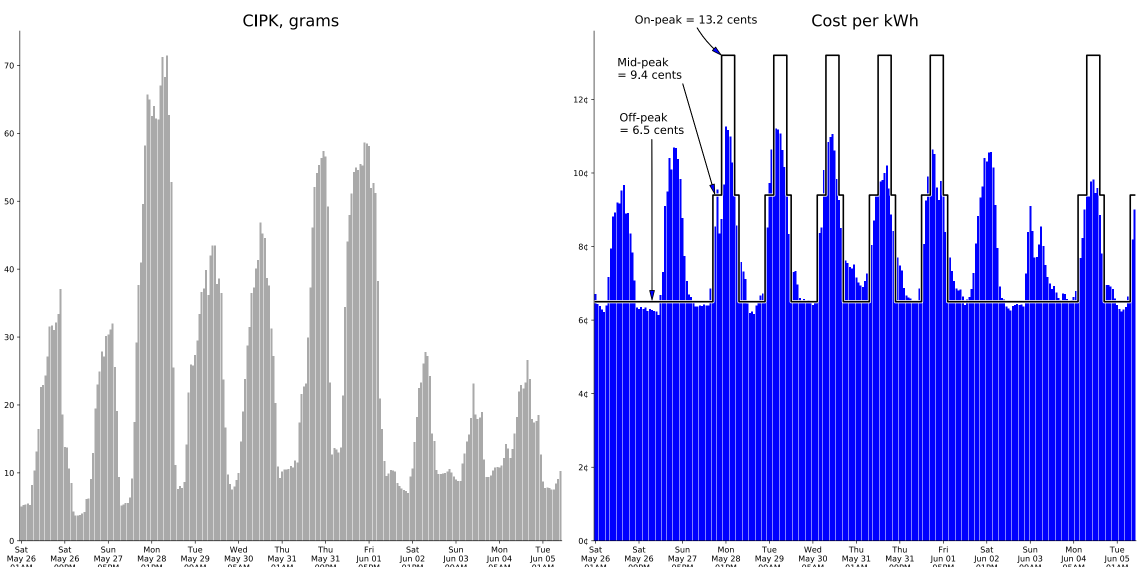


Figure 3.5: Ontario hourly CIPK, cost per kWh, May 26–June 5 2018.

Figure 3.6 shows the changes that occurred in the German fuel mix over the period 1996–2015, and the household price of electricity over the same period. Figure 3.8 shows the annual electricity generation $CO_2$ emissions over the same period, together with the household price.

Four things are plain from this data.

1. Price is strongly positively correlated with the energy contributions from Biofuel/Waste, Wind/Solar, Geothermal, and Other; see Table 3.1. Since the latter two are negligible in terms of total electricity generation (see Figure 3.7), and since the fuel mix at the time of the lowest price (in the year 2000; see Figure 3.6) was dominated by coal, gas, and nuclear, it may

be inferred that Biofuel/Waste and Wind/Solar are the main reason for the dramatic increase in cost. Note also that price is strongly *negatively* correlated with nuclear.

2. The amount of nuclear in Germany's system is strongly negatively correlated with the amount of Biofuel/Waste and Wind/Solar—i.e., as the annual kWh contribution of nuclear decreased beginning in 2011, those of Wind/Solar and Biofuel/Waste increased.[6] This may suggest that Germany attempted to replace nuclear with these generation types. See Table 3.2.

3. The amount of $CO_2$ from electricity generation did not appreciably change (in fact, went slightly up following 2011; see Figure 3.8) in spite of the addition of significant amounts of Wind/Solar. This is due to the coincident increase in generation from both Coal and Biofuel/Waste, the latter of which, though they are often labeled "renewable," are nonetheless highly $CO_2$ intensive.

4. German citizens, who bore the brunt of the increase in price, saw no appreciable reward, in the form of reduced $CO_2$ emissions, for their increased expenditure. $CO_2$ emissions remained stubbornly stable over the period 1996–2015.

Table 3.1: Germany electricity price and fuel kWh correlations

| Price | 1.00 |
|---|---|
| Gas | 0.66 |
| Coal | -0.74 |
| Oil | -0.24 |
| Biofuel/Waste | 0.90 |
| Nuclear | -0.90 |
| Hydro | -0.12 |
| Wind/Solar | 0.89 |
| Geothermal | 0.72 |
| Other | 0.58 |

Table 3.2: Germany electricity fuel mix correlations

| | Gas | Coal | Oil | Biofuel/Waste | Nuclear | Hydro | Wind/Solar | Geothermal | Other |
|---|---|---|---|---|---|---|---|---|---|
| Gas | 1.00 | -0.45 | 0.01 | 0.62 | -0.52 | 0.05 | 0.58 | 0.46 | 0.36 |
| Coal | -0.45 | 1.00 | 0.54 | -0.64 | 0.56 | 0.44 | -0.55 | -0.34 | -0.15 |
| Oil | 0.01 | 0.54 | 1.00 | -0.25 | 0.14 | 0.69 | -0.17 | 0.11 | 0.28 |
| Biofuel/Waste | 0.62 | -0.64 | -0.25 | 1.00 | -0.95 | -0.04 | 0.97 | 0.82 | 0.64 |
| Nuclear | -0.52 | 0.56 | 0.14 | -0.95 | 1.00 | -0.07 | -0.95 | -0.84 | -0.72 |
| Hydro | 0.05 | 0.44 | 0.69 | -0.04 | -0.07 | 1.00 | 0.04 | 0.31 | 0.49 |
| Wind/Solar | 0.58 | -0.55 | -0.17 | 0.97 | -0.95 | 0.04 | 1.00 | 0.89 | 0.76 |
| Geothermal | 0.46 | -0.34 | 0.11 | 0.82 | -0.84 | 0.31 | 0.89 | 1.00 | 0.94 |
| Other | 0.36 | -0.15 | 0.28 | 0.64 | -0.72 | 0.49 | 0.76 | 0.94 | 1.00 |

Though the mix of clean fuels changed significantly, with nuclear declining and wind/solar increasing, the ratio of clean to polluting fuel in German power generation changed only very little over 1996–2015. Figure 3.9 illustrates this. The year in which the proportion of clean fuels was highest (38.2 percent) was 2004. That is barely distinguishable from 1998, the year in which the proportion was lowest, at 33.7 percent.

[6] Both Wind/Solar and Biofuel/Waste increased exponentially over the period 1996–2015; see Figure 3.7. The growth curves of both could be described using second-degree polynomials.

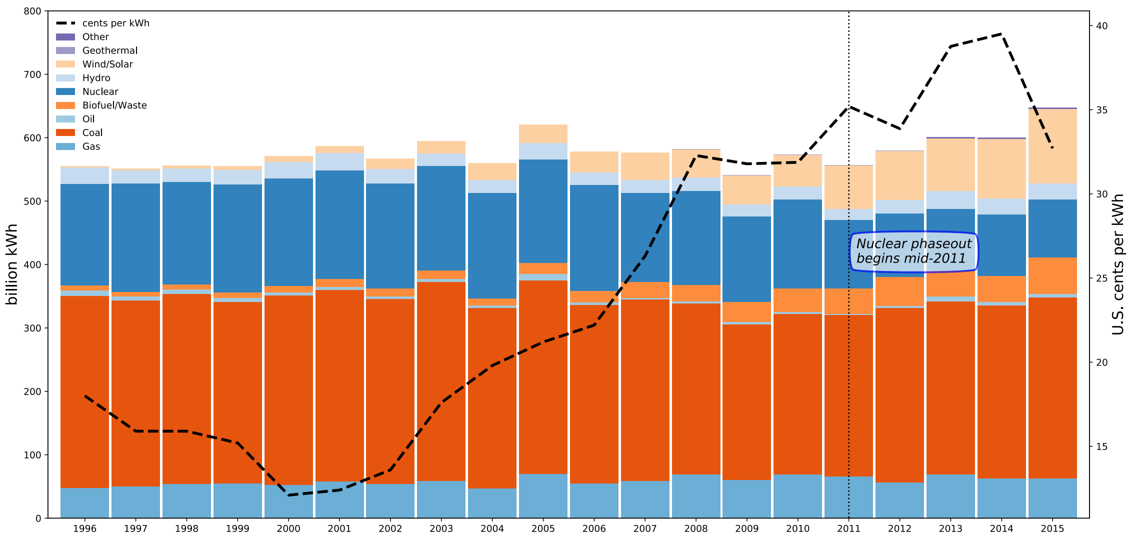


Figure 3.6: Germany generation fuel mix and household price, 1996–2015.

The CIPK of German grid electricity gives another illustration of this. As you can see in Figure 3.10, this did not significantly change over the 20-year period examined.

This indicates there is very little potential for emissions reductions via electrification in Germany.

Yet the household price of German electricity nearly tripled between 2000 and 2015. It is plain that the infusion of massive amounts of renewable and alternative energy into Germany's grid caused the price increase. The fact that this unprecedented infusion did nothing to reduce German electricity generation $CO_2$ emissions ought to call into question the wisdom of copying the German approach to implenenting climate change policy.

Ontario, unlike Germany, did reduce $CO_2$ from electricity generation, and to a very significant degree. However, like Germany, Ontario electricity prices at the household level also dramatically increased. As described in section 3.1.1, a major driver of generation cost is renewable energy (mostly solar, but also wind). Solar represents a very significant cost of $CO_2$ avoidance (Figure 3.3), much higher than those of nuclear and hydro.[7]

Ontario's level of wind and solar represents roughly 20 percent of its generating capacity. Germany's represents more than 25 percent. Alberta's current plan is to increase renewable energy capacity from the current 1,479 megawatts to 5,000 megawatts. This would bring such capacity to roughly 23 percent of Alberta's total generating capacity.

Given that Alberta's intent appears to be to model the German approach, it would be advisable that Alberta and Canadian federal policymakers study the German example in detail. Germany's renewable energy–focused approach to climate change policy appears to have succeeded only in driving household electricity prices up. It certainly did not succeed in reducing $CO_2$ emissions from electricity generation. This has serious implications for Canada's prospects for meeting its 2030 $CO_2$

[7] Though wind is represented as a negative cost of $CO_2$ avoidance in Figure 3.3, this should not be interpreted as indicating it is a viable means of displacing fossil fuel. Wind is non-dispatchable. This, together with its low capacity factor, makes it an ineffective displacer of fossil fuel—this is precisely why Germany, where wind represents a quarter of generating capacity, has failed to reduce electricity $CO_2$ emissions. Wind is represented as a negative cost in Figure 3.3 only because its per-kWh contract remuneration rate in Ontario is less than those of solar and gas.

reduction target. Alberta currently contributes 35 percent of Canada's total anthropogenic $CO_2$, and well over half of Canada's electricity $CO_2$. Unless Alberta achieves sigfnificant and rapid $CO_2$ reductions in electricity generation and other sectors, Canada will not meet its 2030 target.

Section 5 will discuss this in more detail.

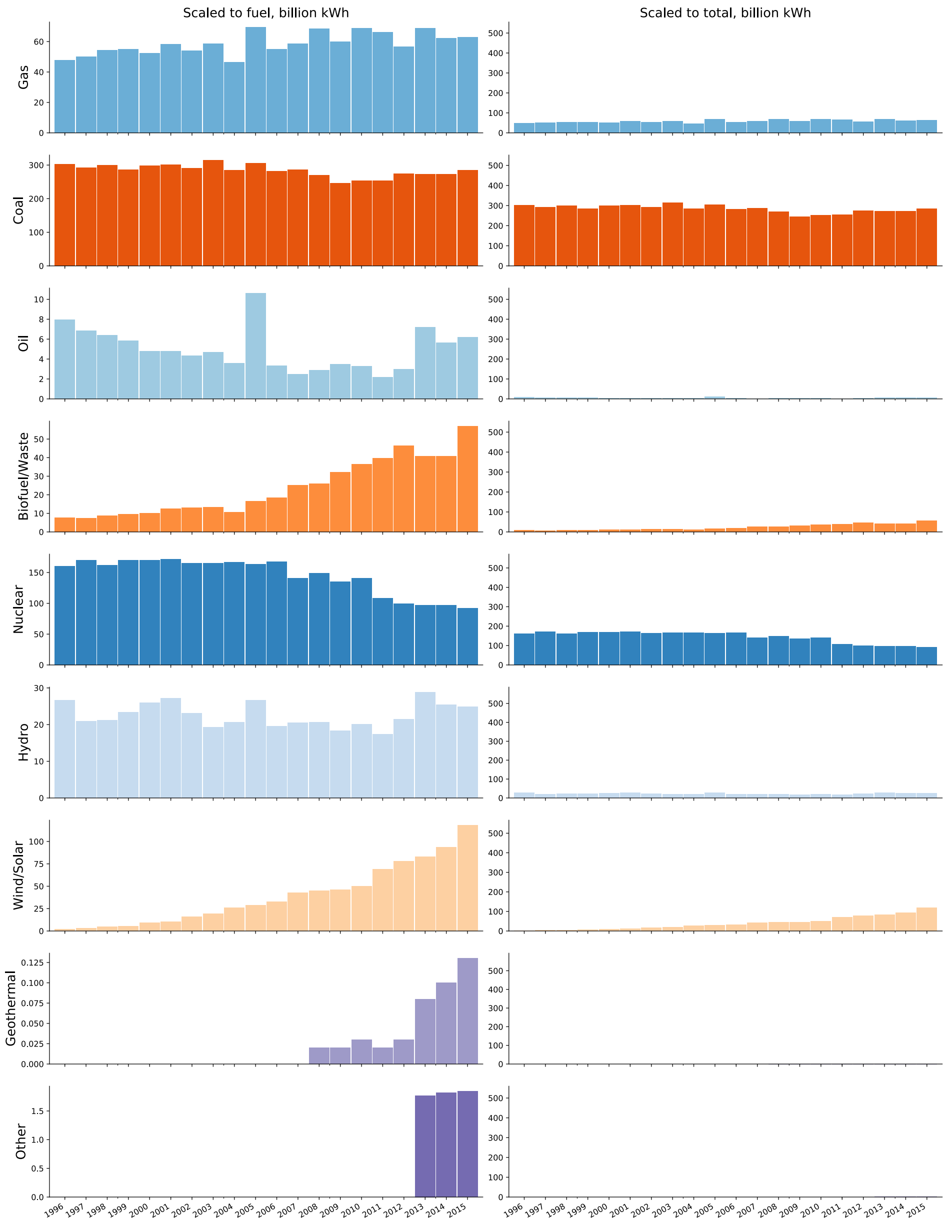


Figure 3.7: Germany individual generating fuel contributions, 1996–2015.

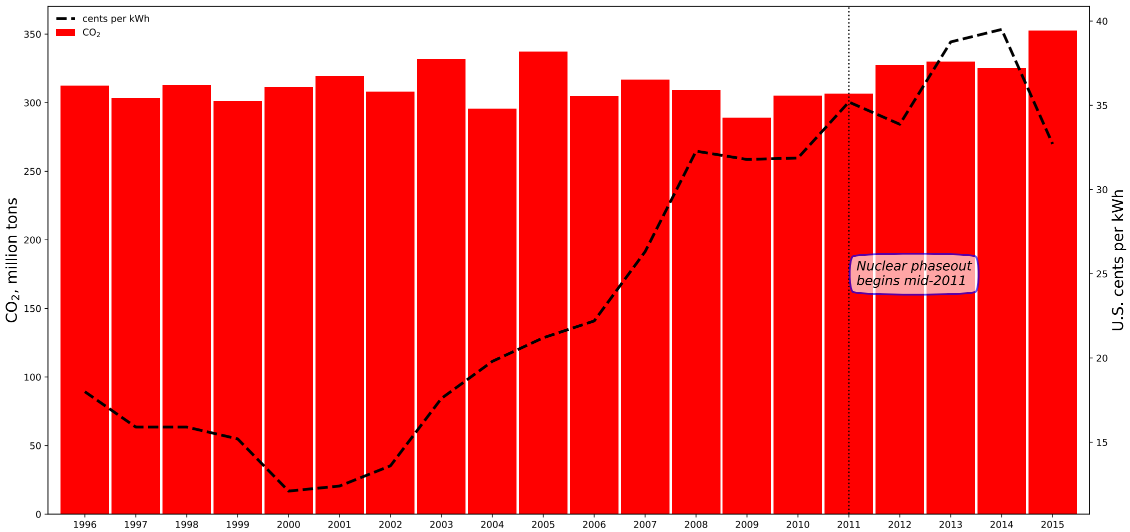


Figure 3.8: Germany electricity $CO_2$ emissions vs price of electricity, 1996–2015.

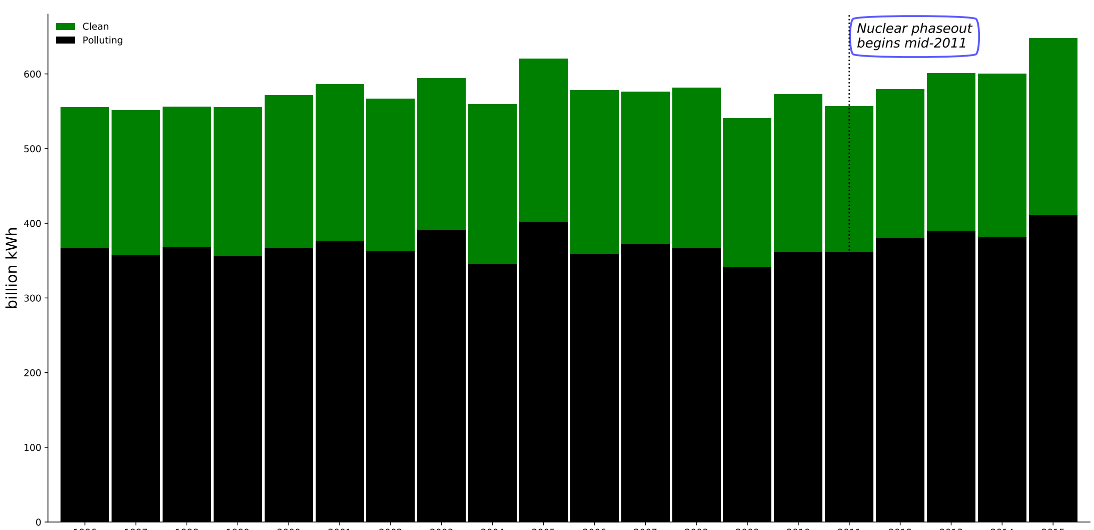


Figure 3.9: Germany electricity fuel mix, clean vs polluting, 1996–2015.

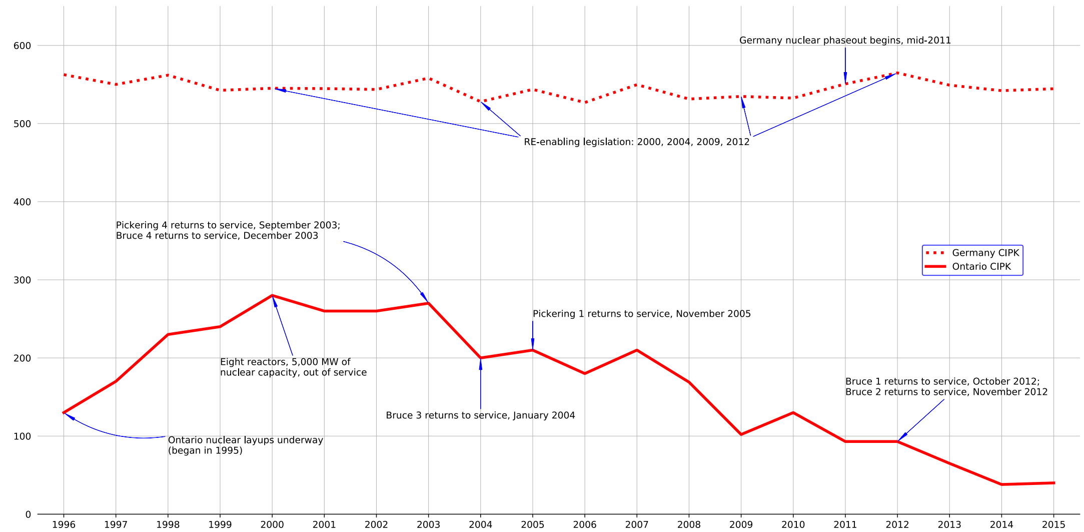


Figure 3.10: Germany vs Ontario grid electricity CIPK, 1996–2015, milestones in respective energy/environment policy implementation.

# Section 4

# Feasibility and GHG implications of electrifying motor vehicle transport

### 4.0.2 All provinces

The generating capacity required to electrify currently gasoline-powered motor vehicle transport was modeled according to seven levels of electric vehicle uptake in the general vehicle fleet. These levels range from five percent to fifty percent.

The result is shown in Figure 4.1.

Bear in mind that so far we are agnostic as to the technology underlying the capacities shown in Figure 4.1. The reason for this is that the emission reductions from displacing gasoline powered cars with EVs is heavily dependent on how electricity is generated.

The starting point for such an analysis is to understand how much less $CO_2$ from gasoline powered transport results from EV uptake at the given uptake levels. This is given in Figure 4.2.

The next step is to understand how much $CO_2$ the EVs that displaced the gasoline vehicles are responsible for, again per uptake level. This is determined by the $CO_2$ intensity per kilowatt-hour (CIPK) of each provincial grid (remember, we have assumed that all EVs are plug-in battery technology). As is apparent from Figure 1.6, there is great variance in the grid electricity CIPKs across the country.

### 4.0.3 Alberta

Figure 1.6 on page 5 shows Alberta's 2015 grid electricy CIPK was 790 grams. This was from generating approximately 61 billion kWh of electricity and emitting approximately 49 million tons of $CO_2$. As you can see in Figure 1.2, the largest single contributor to Alberta's electricity generation was coal, followed by natural gas. Almost all Alberta electricity was generated using polluting fuels (Figure 1.3).

With a grid electricity CIPK of 790 grams, Alberta would achieve only very small $CO_2$ reductions by electrifying a portion of its personal motor vehicle fleet—even if the CIPK of the new generation added to cover increased demand were less than half of 790 grams. Figure 4.3 assumes just that: that the new generation to meet increased demand due to EV uptake is a combination of wind and combined cycle gas, with a combined CIPK of 385 grams. As you can see in Figure 4.3, even if Alberta were to electrify half its gasoline vehicle fleet, overall personal motor vehicle $CO_2$ emission reductions would only be less than 0.9 million tons—a less than 7 percent reduction. This woud be

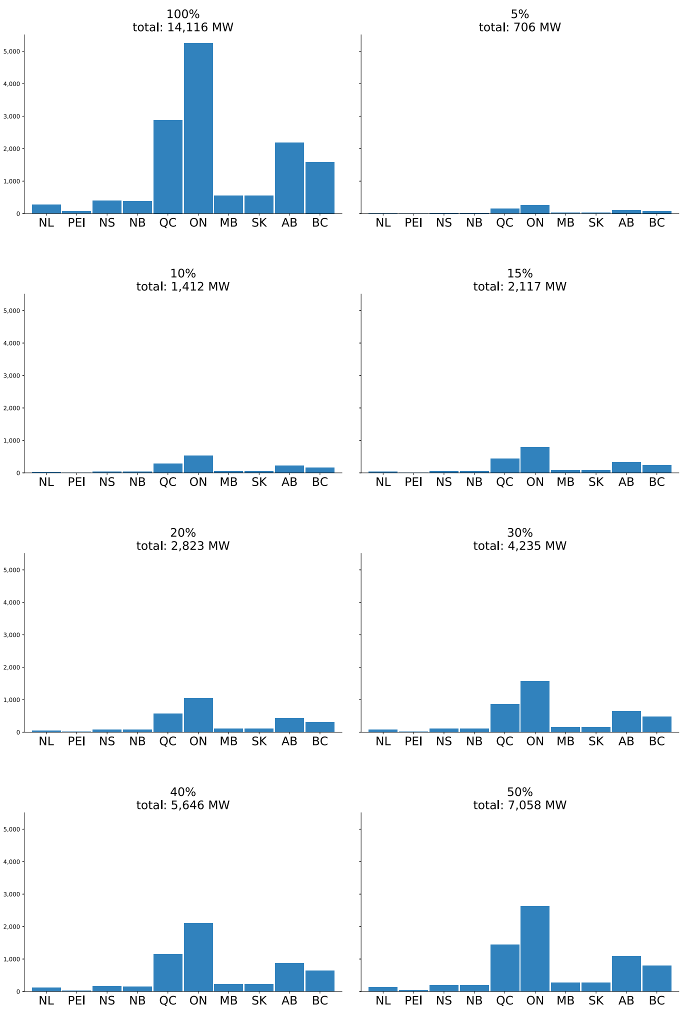


Figure 4.1: Provincial 24/7 generating capacity (MW) required to electrify gasoline-powered vehicle transport, by EV uptake level.

nowhere near adequate to help Alberta contribute to Canada's overall annual reduction target of 200 million tons by 2030.

Moreover, unless Alberta added only zero-emitting generation to cover the increased electricity demand from converting a portion of the motor vehicle fleet to electric, its $CO_2$ emissions from power generation would increase (see Figure 4.4).

For Alberta to achieve significant reductions in $CO_2$ emissions from electricity generation and personal motor vehicle usage, it must:

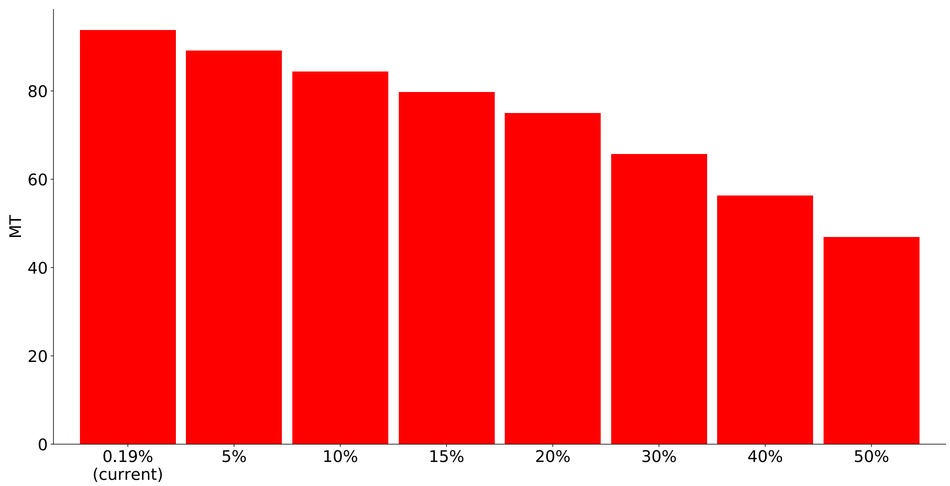


Figure 4.2: Canadian provincial $CO_2$ emissions from gasoline-powered motor transport, reductions due to EV uptake, by uptake level.

- Significantly reduce grid electricity CIPK.
- Electrify as much of the personal motor vehicle fleet as possible.

The only way to lower electricity CIPK is to reduce the CIPK of the individual fuels in the generation fuel mix. As mentioned, Alberta makes most of its electricity with coal and natural gas.

However, if that province were to decarbonize electricity using nuclear power, as shown in Figure 2.2 on page 7, it would achieve very significant $CO_2$ emission reductions both from power generation and motor vehicle transportation. As you can see in Figure 4.5, emission reductions would be much more significant after nuclearization—in fact, the reductions achieved with only a 5 percent EV uptake level are greater than those achieved through a 50 percent uptake in the case of the current grid CIPK.

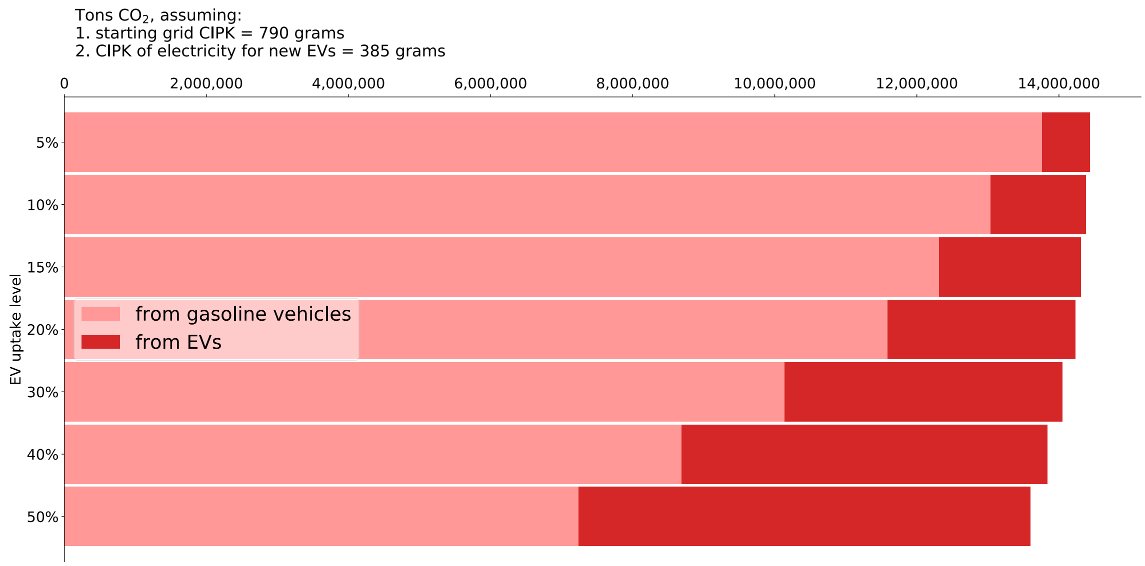


Figure 4.3: Alberta motor vehicle transport $CO_2$ under various levels of EV uptake.

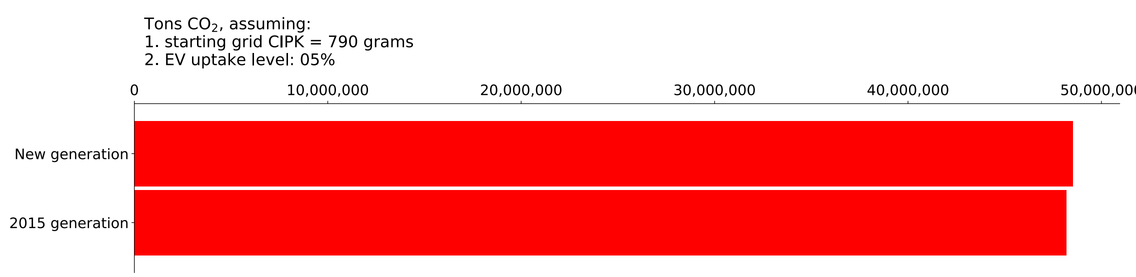


Figure 4.4: Alberta power generation $CO_2$ if (a) current CIPK were unchanged, and (b) CIPK of new capacity added to meet new demand from EVs were 385 grams

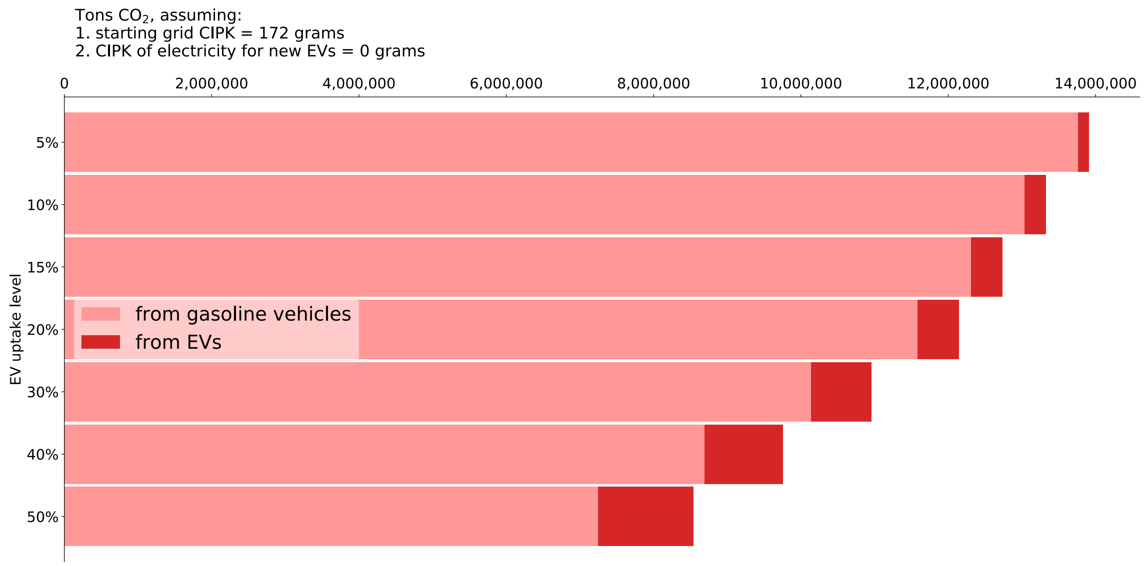


Figure 4.5: Alberta motor vehicle transport $CO_2$ after seven “waves” of decarbonization by nuclearization as shown in Figure 2.2 on page 7

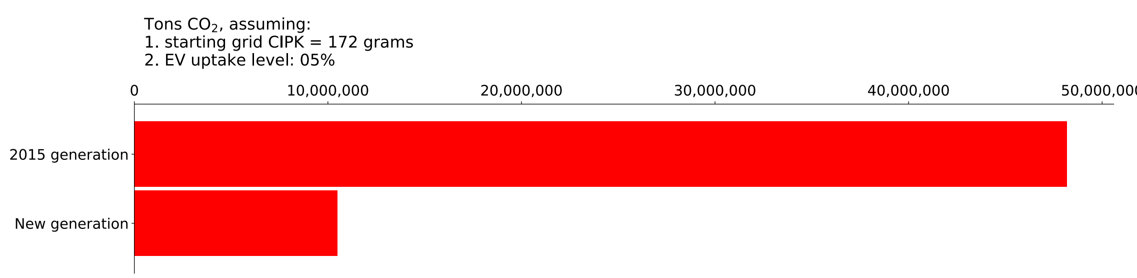


Figure 4.6: Alberta power generation $CO_2$ if CIPK were 172 grams and CIPK of new capacity added to meet new demand for EVs were 0 grams

# Section 5

# Meeting Canada's GHG reduction targets

Canada's current official target is to reduce annual $CO_2$ to roughly 523 million tons by 2030. Current annual emissions are 730 million tons and projected to be 742 million by 2030. The target therefore calls for annual emission reduction of 219 million tons by 2030.

Figure 5.1 shows one possible route to emission reductions on the scale required by Canada's target.

The "Reductions from fossil provinces electricity generation" slice of the right-hand column in Figure 5.1 gives an idea of the size of the challenge Canada faces in achieving the 2030 target. This slice represents 77 million tons, or 35 percent of the required 219 million ton reduction.[1]

Achieving this would require significant replacement of currently fossil-fired energy with non-polluting energy. To illustrate how significant, consider the case of Alberta electricity generation. Figure 5.3 models the clean-vs-polluting generation fuel mix, beginning in 2020, that would be required for Alberta to nearly fully decarbonize electricity generation by Canada's target date of 2030, while meeting the increase in demand for electricity due to electric vehicle uptake.

However, as you can see in Figure 5.3, the trend in clean vs polluting electriciy generation in Alberta over the period 1990–2015 does not indicate that the province is on track for such a decarbonization.

To achieve a decarbonization in this way and of this magnitude, Alberta would have to complete the decarbonization of electricity generation shown in Figure 2.2. This would require adding, on top of the 4,900 MW of zero emitting capacity modeled in Figure 2.2, a further 2,100 MW of capacity so as to cover Alberta's current 7,000 MW combustible baseload.

Alberta would also have to fully electrify personal motor vehicle transportation. This would require adding 2,000 megawatts of additional baseload electricity generating capacity.[2] This would require at least one of the following:

- 2,000 megawatts of nuclear capacity (see the Alberta bar in the "100%" EV uptake level shown in Figure 4.1 on page 23).
- 6,000–8,000 megawatts of wind capacity.
- 13,000–14,000 megawatts of solar PV plus some kind of grid-scale storage.

[1] As you will recall from section 2.1.1, a seven-wave nuclearization of electricity generation in Canada's fossil provinces would reduce those provinces' collective generation $CO_2$ emissions by 77 million tons.

[2] This assumes the adoption of and adherence to "controlled" charging whereby the charging of EV batteries takes place at regular times so as to match generating capacity with the demand for charging.


Figure 5.1: A possible route to Canada's 2030 $CO_2$ reduction target

Section 3 illustrates the perils of adopting the German and Ontario approaches of massive infusion of wind and solar into traditional grids. This was shown to have only added significantly to electricity prices at the household level in both of those jurisdictions. In Germany, this did nothing to reduce $CO_2$; in Ontario it did little to reduce electricity $CO_2$ while likely adding to the $CO_2$ from domestic heating as a result of fuel switching due to the wider price difference per kWh between natural gas and electricity. Ontario's very significant electricity $CO_2$ reductions were achieved by returning significant amounts of nuclear generation to the grid.

If Alberta copies the German and Ontario approach to renewable energy, it can expect the same result: dramatically elevated household electricity prices and little if any progress in reducing $CO_2$ in electricity generation or any of the sectors that are amenable to electrification, e.g. transport and heating. However, if Alberta were to copy Ontario's approach to nuclear energy, it can expect rapid and dramatic reductions in $CO_2$ with relatively low and stable prices. If it then based extra-electricity-sector electrification on low- or zero-$CO_2$ electricity, its reductions would be amplified.

Similarly, the "Reductions from gasoline-powered motor vehicles" slice, discussed in Section 4, requires a major, coordinated effort. This reduction of 47 million tons assumes that half of current gasoline powered motor vehicles in Canada's ten provinces have been replaced with electric vehicles with batteries charged from each provincial grid. Moreover, it assumes that *the additional electrical energy generated in each province to meet the demand for EV battery charging has come from non-polluting sources.* The latter would require that a total of over 7,000 megawatts of non-polluting generating capacity is added across the ten provinces (see Figure 5.2).

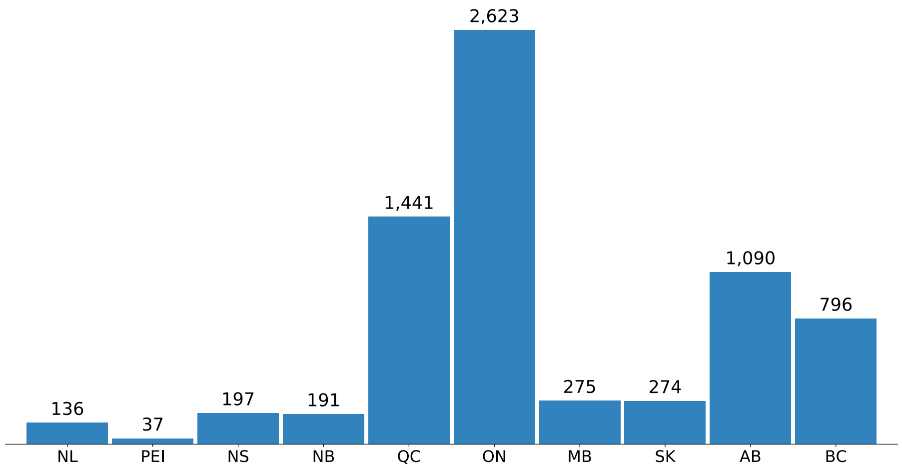


Figure 5.2: Generation capacity required in each province to meet EV demand, 50 percent EV uptake level. Megawatts.

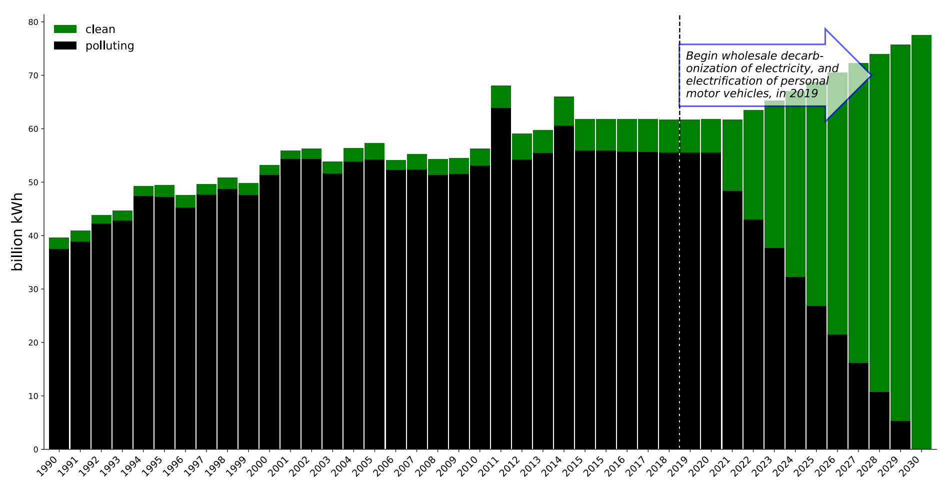


Figure 5.3: Alberta required replacement of polluting with clean fuel in electricity generation to decarbonize both electricity and personal motor vehicle transport. Total $CO_2$ reduction from both activities would be approximately 63 million tons—or 28.7 percent of the 219 million tons Canada has committed to eliminating from the national inventory by 2030. Alberta currently emits over 35 percent of Canada's anthropogenic $CO_2$.