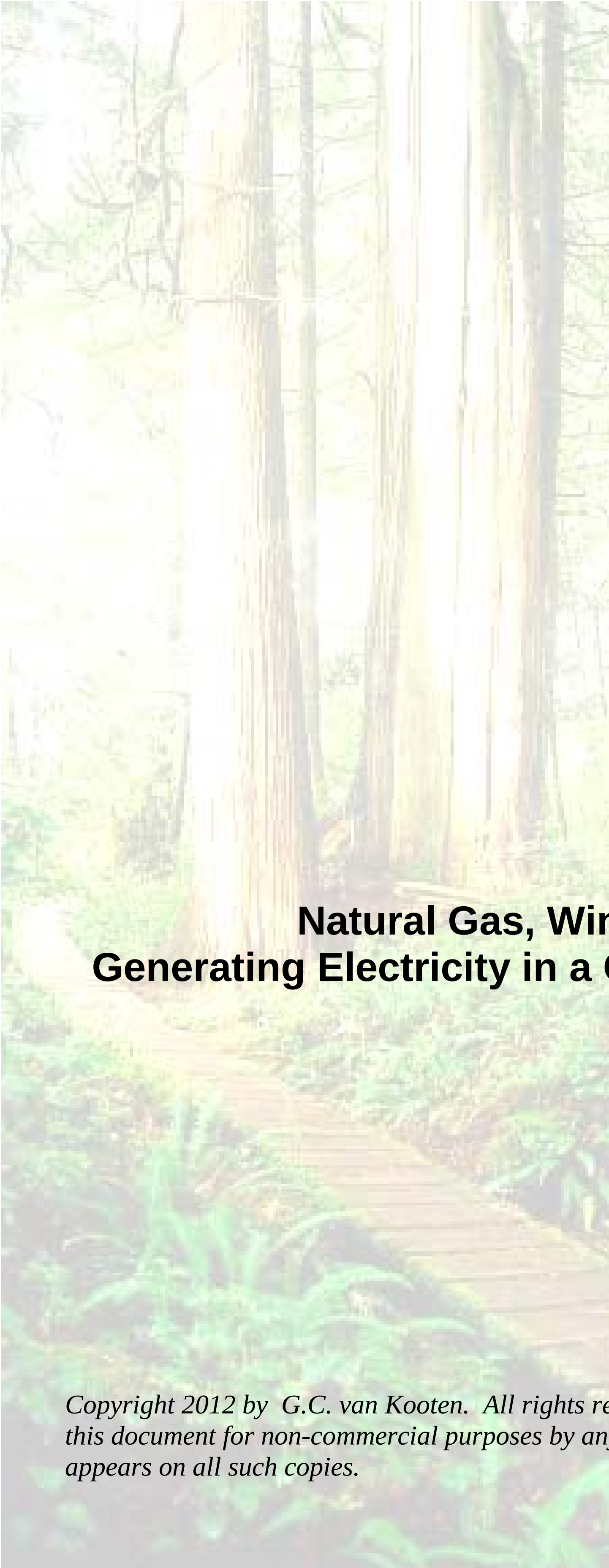

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Natural Gas, Wind and Nuclear Options for Generating Electricity in a Carbon Constrained World

Gerrit Cornelis van Kooten

April 2012

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Natural Gas, Wind and Nuclear Options for Generating Electricity in a Carbon Constrained World

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Abstract

A linear programming model is used to examine the impact of carbon taxes on the optimal generation mix in the Alberta electrical system. The model permits decommissioning of generating assets with high carbon dioxide emissions and investment in new gas-fired, wind and, in some scenarios, nuclear capacity. Although there is an intertie from Alberta to the U.S., the focus is on the connection to British Columbia as wind energy can potentially be stored in reservoirs behind hydroelectric dams. However, storage can also be used to smooth out the net load facing nuclear facilities. A carbon tax facilitates early removal of coal-fired capacity, which is replaced by low-emissions gas plants. It is only when the carbon tax exceeds \$125/tCO2 that wind enters the system, although wind is displaced by nuclear power if that option is permitted. Although upfront costs of adding nuclear capacity are prohibitive, nuclear outcompetes wind because wind farms have low capacity factors and, importantly, because a great deal of gas-plant capacity is required to support wind, something avoided when nuclear energy is added. Finally, an intertie with British Columbia is beneficial because of the support it provides for wind and nuclear energy, but the role of natural gas is more important in facilitating a transition to lower system-wide carbon dioxide emissions.

Key Words: renewable energy, nuclear power, transmission capacity, energy storage

JEL Categories: Q42, Q54, Q48, Q58

Introduction

A carbon tax is viewed by many as an economically efficient means to incentivize carbon-reducing investments in electrical generating systems that might include natural gas, wind and nuclear assets. Along with growing demand for electricity and a desire to reduce greenhouse gas emissions, there has been a renewed discussion about the role nuclear power might need to play in meeting carbon dioxide emission reduction targets in many jurisdictions. However, recent concerns related to the failure of the Fukushima Daiichi nuclear power plant in Japan to withstand an earthquake and tsunami has reduced society's already low confidence in the safety of nuclear power. As a result, renewable sources of electrical generation, such as wind, are seen as a better alternative to fossil fuel sources of energy for safely generating electricity and reducing CO_2 emissions.

Increasing reliance on wind generation poses many challenges for electrical system operators, because of the variable nature of wind, lack of storage, need for backup generation, and transmission constraints and costs of building additional transmission capacity. Wind speeds vary considerably and sometimes unexpectedly within an hour, throughout the day or season, and even from year to year. The intermittent nature of wind requires that wind generation be supplemented by fast-ramping backup generation from open-cycle gas turbine (OCGT) and/or diesel power plants; this results in significant CO_2 emissions from these plants due to more frequent starts and stops and operation at less than optimal capacity (Prescott and van Kooten 2009). The need for fast ramping technologies is magnified when there is inadequate transmission capacity (Maddaloni et al. 2008). However, an ability to store intermittent wind-generated power behind hydroelectric dams, which are also relatively fast ramping, can compensate for variability of wind, solar, wave and tidal energy sources.

Nuclear power plants are an alternative means for reducing CO_2 emissions from electricity generation. They have high capacity factors and other operating characteristics that allow them to substitute for coal-fired and closed-cycle gas turbine (CCGT) base-load facilities that meet the bulk of a system's load. Indeed, an MIT study (Deutch et al. 2009) recommends that, if significant reductions in global CO_2 emissions are needed to stabilize the climate, installed capacity will need to increase from the current 100 GW to 300 GW in the United States by 2050 and from 340 GW to 1000 GW globally. Despite finding that nuclear power could be competitive with coal and natural gas, and even before the nuclear disaster in Japan, the MIT study found that their target was far from being realized.

From an environmental standpoint, wind and nuclear energy have several drawbacks. Wind turbines are considered visually unappealing, turbine noise has been linked to health concerns and wind farms kill many birds, including raptors and other birds that are considered species at risk. Further, because wind turbines and wind farms are scattered across a vast landscape, construction of costly additional transmission capacity and associated spillovers constitute obstacles to political acceptability. On the other hand, disposal and transportation of nuclear waste, and fears associated with a potential nuclear accident, terrorist attack and nuclear proliferation, are major drawbacks of nuclear power (Deutch et al. 2009). In this paper, we abstract from these externalities and focus solely on the externality associated with CO_2 emissions. In this way, we can examine optimal investment in and decommissioning of generating assets in response to market incentives that increasingly penalize fossil fuel production of electricity.

We focus on the Alberta electricity system because it has a high proportion of fossil fuel generating assets, the reduction or elimination of which would result in substantial CO_2 savings. Further, there is the potential to link to British Columbia via an existing transmission link. The advantage of the interprovincial intertie is that BC is dominated by large-scale hydroelectric assets, so that wind power generated in Alberta can be easily stored in BC reservoirs. Currently most of Alberta's electricity needs are met by plants that burn coal or natural gas, with minor production from hydroelectric, biomass and, more recently, wind sources. While there is interest in technologies such as geothermal, expanded biomass and solar, these technologies will not likely play a significant role in Alberta's energy sector in the foreseeable future.[1] In response to an increasing load and growing environmentalism related to the high CO_2 emissions from oil sands production, wind and nuclear alternatives to coal and natural gas are increasingly seen as viable options.

The objectives of the current research are, therefore, to (1) investigate the potential to reduce CO_2 emissions and make wind energy more attractive by exchanging power between British Columbia (where variable wind energy can be stored) and the Mid-Columbia (MidC) region in the United States; (2) analyze the impact that varying levels of CO_2 taxes will have on Alberta's optimal generation mix; and (3) examine the potential of nuclear power as an alternative energy source. In doing so, we also consider how the system costs are impacted and the extent to which CO_2 emissions can be abated. To assess these objectives, a mathematical programming model is developed for the Alberta electricity grid that has the ability to connect to the BC and MidC grids. The model builds upon earlier work by Benitez et al. (2008) and

[1] Geothermal sites are limited, while solar suffers from the same problem as wind, namely intermittency, plus much reduced output during winter months because of its northern location.

Scorah et al. (2012).

Methods

The costs and benefits of introducing wind power into an electricity grid depend on the system's generating mix. Since the Alberta electric system is dominated by fossil fuel generation, CO_2 emissions can be reduced at relatively low cost as wind penetrates the grid. As Scorah et al. (2012) find, these benefits are enhanced by trading power with British Columbia. The objective function used by these authors was to minimize the cost of producing electricity. Along with the device of excessively high ramp rates for coal and CCGT assets, minimization of costs was used to force trade between the two provinces. In the current study, we extend their modeling approach to include trade with the U.S. and use price differentials to incentivize trade between regions. In addition, in the mathematical programming model that we develop a carbon tax is used to promote decommissioning of fossil fuel assets and investment in wind farms and/or nuclear facilities that have little or no emissions.

Although Alberta's power system is completely deregulated, for convenience it is assumed the Alberta Electric System Operator (AESO) allocates generation across assets based on knowledge about load and power output from must-run assets, including wind. The AESO also chooses how much electricity to import or export across interties to the U.S. (MidC) and British Columbia; this decision is based on the prices in the various jurisdictions and transmission line capacities (discussed below). Finally, the authority also decides on the decommissioning of extant fossil-fuel generation assets and investment in new (wind, nuclear or alternative fossil-fuel) assets; thus, the authority can invest in assets which are assumed to appear instantaneously at the beginning of the one-year time horizon. In essence, the AESO is assumed to maximize annual profit subject to load, trade and engineering constraints.

The profit function can be written as follows:

$$(1)\ \Pi = \sum_{t=1}^{T}\left[P_{A,t}D_t - \sum_i \left(OM_i + b_i - \tau\varphi_i\right)Q_{ti} + \sum_{k\in[BC,MID]}\left\{\begin{matrix}\left(P_{A,t} - (P_{A,t} - P_{k,t} - \delta)M_{k,t}\right)\\ + \left(P_{k,t} - (P_{k,t} - P_{A,t} - \delta)X_{k,t}\right)\end{matrix}\right\}\right] + \sum_i (a_i - d_i)\Delta C_i$$

where Π is profit ($); i refers to the generation source (*viz.*, natural gas, coal, nuclear, wind, hydro); T is the number of hours in the one-year time horizon (8760); D_t refers to be the demand or load that has to be met in hour t (MW); Q_{ti} is the amount of electricity produced by generator i in hour t (MW); OM_i is operating and maintenance cost of generator i ($/MWh); and b_i is the variable fuel cost of producing electricity using generator i ($/MWh), which is assumed constant for all levels of output. We define $P_{j,t}$ to be the price ($/MWh) of electricity in each hour, with $j \in$ {A, BC, MID} referring to Alberta, British Columbia and MidC, respectively. While Alberta and MidC prices vary hourly, the BC price is fixed at $90/MWh. $M_{k,t}$ refers to the amount imported by Alberta from region $k \in$ {BC, MID} at t, while $X_{k,t}$ refers to the amount exported from Alberta to region k; δ is the transmission cost ($/MWh).

In addition, C_i refers to the capacity of generating source i (MW). The last term in (1) permits the addition or removal of generating assets, where a_i and d_i refer to the annualized cost of adding or decommissioning assets ($/MW), and ΔC_i is the capacity added or removed. For wind assets, ΔC_W is measured in terms of the number of wind turbines that are added (no reduction in numbers is permitted), each with a capacity of 2.3 MW. Given that wind energy is non-dispatchable ('must run'), a sink is assumed available in each period (denoted S_t) where excess energy can be directed or retrieved if the system cannot respond quickly enough because of extreme variability in wind power output from one period to the next. Further, R_i is the amount of time it takes to ramp production from plant *i*. Transmission between Alberta and BC, and Alberta and MidC, is constrained depending on whether power is exported or imported; the import and export constraints are denoted TRM_k and TRX_k, respectively, with *k* defined above. Finally, τ is a carbon tax (\$ per tCO_2) that we use to incentivize removal of fossil fuel capacity and entry of renewable or nuclear capacity, and φ_i is the amount of CO_2 required to produce a MWh of electricity from generation source *i*.

Objective function (1) is maximized subject to the following constraints:

(2) Demand is met in every hour: $\sum_i Q_{t,i} + \sum_{k\in[BC,MID]} \left(M_{k,t} - X_{k,t}\right) - S_t \geq D_t, \forall t = 1,\ldots,T$

(3) Ramping-up constraint: $Q_{t,i} - Q_{(t-1),i} \leq \frac{C_i}{R_i}, \forall i, t = 2,\ldots,T$

(4) Ramping-down constraint: $Q_{t,i} - Q_{(t-1),i} \geq -\frac{C_i}{R_i}, \forall i, t = 2,\ldots,T$

(5) Capacity constraints: $Q_{t,j} \leq C_i, \ \forall\ t,i$

(6) Import transmission constraint: $M_{k,t} \leq TRM_k, \ \forall\ k,t$

(7) Export transmission constraint: $M_{k,t} \leq TRK_k, \ \forall\ k,t$

(8) Non-negativity: $Q_{t,i}, M_{k,t}, X_{k,t} \geq 0, \ \forall\ t,i,k$

In any given hour, electricity can only flow in one direction along a transmission intertie. To model this constraint requires the use of a binary variable for each intertie in the model. To avoid such a nonlinear constraint, we assume that $TRM_k = TRX_k = TCAP_k$, $\forall k$, although this applies only to the Alberta-BC intertie, and then employ the following linear constraint to limit the flow of electricity to one direction:

(9) $X_{k,t} + M_{k,t} \leq TCAP_{k,t}, \ \forall \ k,t.$

Some 1200 GWh of hydroelectricity is produced annually in Alberta, with more than 70% constituting run-of-river output that is non-dispatchable. The remainder is generated by two dams (Bighorn and Brazeau) with a combined generating capacity of 475 MW; however, their combined capacity factor is less than 10% as the dams are primarily used for flood control. In the model, therefore, hydroelectricity is treated primarily as must run (and subtracted from load), although a small subcomponent of the model simulates the operation of a hydro facility; thus, the system has some capacity to store wind generated electricity. A description of the hydroelectric subcomponent of the model is found in Louck et al. (1981).

The startup and shut down of individual generators is not modeled. It is assumed that all generators of a given type operate efficiently, with only the marginal generator's output fluctuating (ramping) up and down as needed. No effort is made at this time to model the change in emissions intensity that results when a (marginal) generator operates below its optimal rated capacity. Generators that are not needed are removed, although decommissioning of capacity is assumed to be continuous – ΔC_i is continuous and not lumpy. Further, the added costs of shutdown and startup of thermal power plants associated with wind variability are not taken into account.

The decision variables in the model are Q_{ti}, $M_{k,t}$, $X_{k,t}$ and ΔC_i, including ΔC_W which is determined by increases in the number of wind turbines beyond those currently in place.

Data

The Alberta electricity grid currently has 6240 megawatts (MW) of coal capacity, 3800 MW of natural gas-fired base-load capacity, 1500 MW of peak-load gas load plants, 310 MW of biomass generation, approximately 900 MW of installed hydroelectric capacity, and 805 MW of installed wind capacity. As noted above, 425 MW of hydro capacity is must run, while the operation of the reservoirs generates very little energy throughout the year; hydroelectric power generation depends on river flows, reservoir capacities and other uses of water. For convenience, we treat biomass generation as equivalent to coal.

Transmission interties exist between Alberta and the BC and MidC regions. Alberta is able to export up to 600 MW to BC at any given time, but can only import 760 MW from BC due to constraints within the Alberta grid. However, we assume a single transmission capacity constraint of 650 MW (for reasons noted above), varying it to examine the impact of potentially greater storage on the optimal generating mix. BC is dominated by hydroelectric generation, which accounts for 11,000 MW or 92.4% of BC generating capacity, and thus has the capacity to store energy from Alberta. Alberta may also import or export up to 300 MW of electricity from the MidC region of the U.S. This system is made up of coal-fired, hydroelectric, nuclear and renewable (mainly wind) generating resources. Load data used in the model are for Alberta, while BC and MidC prices are used along with Alberta prices to determine movements along the interties.

Load and price information are provided in Table 1. Although not used in the model, 2008 load data for BC are also provided in the table. Notice that the peak load in Alberta is only 57% higher than the minimum load, while BC's peak load is 130% higher. One possible explanation relates to the composition of the industrial sector, which is the major consumer of energy in the two provinces. Alberta is more heavily industrialized because of its much larger energy sector. Since large industrial plants operate around the clock, electricity demand varies little between daytime and nighttime. In BC, the forest sector is a major power consumer but many sawmills do not operate around the clock, especially during times of low demand, plus sawmills and pulp mills generate some of their own electricity using residual biomass.

Table 1: Load and Price Data used in Model, 2010[a]

	Alberta	British Columbia	Mid-Columbia
Load (MW)			
Average	8,188	7,005	-
Maximum	10,227	10,855	-
Minimum	6,524	4,703	-
Energy Price ($/MW)			
Average	90	75	56
Maximum	1,000	-	127
Minimum	0	-	0

[a] For BC, load data are for 2008 (the latest year available) and a price is assumed.

If wind power is non-dispatchable or must run, remaining generators in the system must ramp up and down to meet the adjusted load, where wind generated power is subtracted from load. The general effect of integrating wind into an existing grid is to increase the variability of the adjusted load. This is illustrated in Figure 1 where Alberta load and wind-adjusted load for the first ten days in January 2010, and the last ten days in December 2010, are provided in ten-minute intervals. During 2010, installed wind capacity rose from 501 MW to 715 MW, or by 42.7%; if we define wind penetration as installed capacity divided by peak load, wind penetration increased from 5% to nearly 7% throughout the year. Not surprisingly, the wind-adjusted load in the beginning of 2010 is impacted less by wind resources than that at the end of the year – the wind-adjusted load is more variable at the end of 2010 (Figure 1b) than it is at the beginning (Figure 1a). As wind penetration increases, existing coal and some natural gas assets have more difficulty following the wind-adjusted load than the normal load.

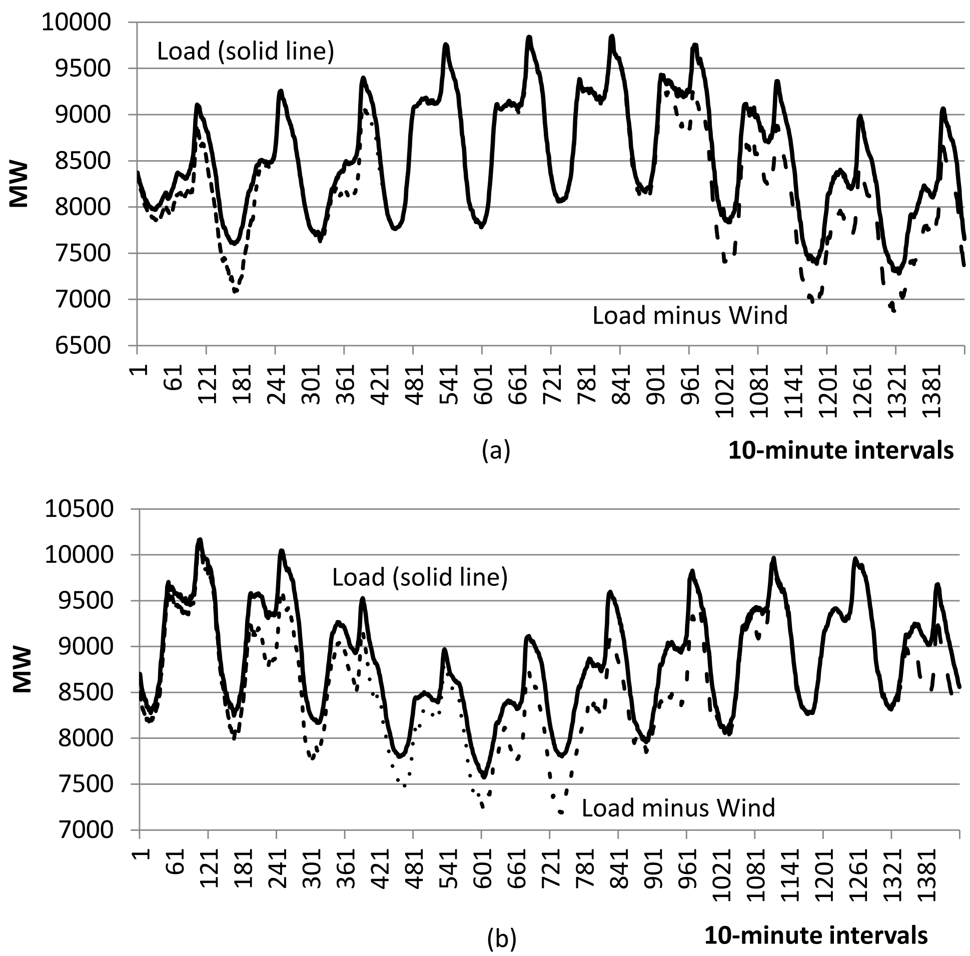

Figure 1: Alberta Load and Wind Generation at 10-minute Intervals, First 10 Days in 2010 (panel a) and Last 10 Days in 2010 (panel b)

It is important to note that there are extended periods when the wind does not blow, and no wind power comes onto the grid. At the beginning of 2010, for example, there was no wind from 6 pm on January 2 until 5 am the next morning, and again from 10 minutes after midnight on January 4th until the evening of January 6. Since wind farms in Alberta locate in the south, just east of the Rocky Mountains, to take advantage of prevailing winds, even if wind capacity had been greater, there would not have been additional wind generated electricity. This is seen in the late December data, when 214 additional MW of capacity were available: wind power output began to collapse in the late afternoon of December 29, was non-existent for the entire morning of December 30, and did not begin to pick up again until the evening of December 31; in essence, there was little or no wind for a period of 50 hours (Figure 1b).

In addition to the information discussed above (transmission constraints, prices, load, wind output), the model takes into account some run-of-river hydroelectricity (produced by a series of dams on the Bow River). The non-wind, non-dispatchable run-of-river assets account for an average 211.6 MW of electricity per hour that ranges from 60 to 360 MW.[2]

Finally, information on construction and operating costs, emissions and ramping rates for generators is required for the model. This information is provided in Table 2. The cost of installing new generating capacity or decommissioning extant capacity is amortized to an annual basis using a 10% rate of discount. Newly constructed nuclear, coal and gas plants are assumed to last only 30 years and wind turbines 20 years. This intentionally biases fixed costs against plants that have a longer life span, such as nuclear plants that are still operating after 40 years.

The AESO (2010) estimates the system ramping rate to be around 100 MW per 10 minutes, although they vary by asset (see Table 3). As indicated in Table 3, the majority of coal and gas plants cannot ramp any faster than 5 MW per 10 minutes. However, the average delay to a response for dispatch was about four minutes; this also needs to be taken into account in

[2] In the Alberta system, there also exists must-run power co-generated with heat that uses natural gas as an energy source. Lacking data on co-generation, we do not include this aspect except via the system's ramping rates, which are discussed below. In essence, ramping rates are slower than would normally be the case for gas plants to account for co-generated power.

determining the ramp rate. Based on this information and that in Table 3, we calculate the ramp rates for different sorts of assets in the last column of Table 2, but then on an hourly basis and as a percent of capacity.

Table 2: Construction and Operating Costs ($2010), Carbon Dioxide Emissions, and Ramp Rates of Various Generating Assets

		Construction Costs[a]		Variable Costs ($/MWh)[b]			Ramp rate
Asset	Years to build	Overnight ($/kW)	Decommission as % of overnight	O&M	Fuel	Emissions (tCO_2/ MWh)[c]	% of capacity per hour[d]
Nuclear	7	5400.0	42.8	11.00	7.70	0.020	1.0
Biomass	2	1280.0	22.2	6.60	92.70	0.250	2.5
Coal	4	1777.0	24.0	6.60	5.43	0.850	2.5
Wind	3	1300.0	n.a.[e]	0.17	0.0	0.015	n.a.[e]
Hydro	4	2100.0	n.a.[e]	3.64	1.01	0.009	n.a.[e]
CCGT	3	965.4	10.0	4.76	13.97	0.450	7.5
OCGT	2	694.8	10.0	4.65	14.03	0.450	12.5

Notes:

[a] Overnight costs are the total costs of labor, materials, etc. required to build the facility immediately or overnight. Hence, they need to be adjusted for the construction time. As an approximation, divide the overnight cost by the time required to build the plant and then discount the stream of costs to the present. For biomass, the overnight cost is that of converting coal-fired generation to biomass. Asset decommissioning costs are taken to be a percent of overnight construction costs. For nuclear, Fox (2011) uses $3037.2/kW but The Economist (2012) reports the figure provided here as the most costly one found in actual construction. Remaining data are from van Kooten (2010, 2012) and Fox (2011).

[b] Fuel and O&M costs for nuclear power from http://world-nuclear.org/info/inf02.html (accessed March 22, 2012). For gas plants, O&M costs are calculated from Northwest Power Planning Council (2002). Calculated values of $3.90/MWh and $3.81/MWh for 2002 are inflated by the CPI to get $4.76 and $4.65/MWh for 2010 for CCGT and OCGT plants, respectively. Fuel prices for coal and gas are U.S. prices for Mountain region for December 2010 (respectively, $1.59 and $4.09 per million btu) multiplied by 3.41442594972 to convert to $/MWh; higher price for OCGT comes from Pacific region gas price of $4.11/mil btu. Price data are from U.S. Energy Information Administration (2012, p.106). Remaining data are from van Kooten (2012).

[c] Source: Calculations based on van Kooten (2010, 2012) and Fox (2011)

[d] Estimates based on information in Table 3 and total system ramp rate of 600 MW per hour.

[e] not applicable.

Table 3: Distribution of Maximum Ramp Rates for 67 Assets Participating in the Alberta Market[a]

Ramp Rate (MW/Minute)	≥30	25-30	20-25	15-20	10-15	5-10	≤5
Number of assets	4	1	1	0	9	24	28

Notes:
[a] This refers to the current distribution and is based on bidding information for assets making non-zero offers and participating in the market since 2008.
Source: AESO (2010, p.13)

Model Results

The Government of Canada (2011) aims to reduce its greenhouse gas emissions by 17% from 2005 levels by 2020 as inscribed in the December 2009 (non-binding) Copenhagen Accord. This implies that Canada's CO_{2e} emissions would need to be reduced from 731 Mt in 2005 to 607 Mt in 2020. Coal currently accounts for 93 Mt of emissions, representing 78% of the emissions from the electricity sector. Eliminating coal-fired power will go a long way to meeting this objective. However, as a member of the G8, Canada also implicitly agreed to reduce its emissions of CO2e by 80% from 2005 levels at a meeting in L'Aquila, Italy, on July 8, 2009.

To better understand how Alberta's optimal generating mix might respond to climate mitigation policies that aim to achieve these targets, and whether the latter target is even feasible, we employ a carbon tax on emissions in the electricity sector that varies from \$0 to \$200 per tCO_2. We investigate scenarios with zero, moderate and high transmission capacity along the Alberta-BC intertie and a situation where nuclear energy is allowed into the mix in addition to wind. The latter possibility is included to determine whether, with a very severe emission reduction target (very high carbon tax), it might be possible to reduce CO_2 emissions by 80%. In essence, we wish to determine whether nuclear energy can compete with wind and whether nuclear power is needed to attain the most severe targets.

Capacity and Generation

Consider first the impact of the carbon tax on optimal installed generating capacity, or the generation mix, and then the amount generated by each source during the year. In Table 4, the existing (initial) generating mix is provided in the first row, followed by results for the case where no trade is possible with jurisdictions adjacent to Alberta and then the case where there exist interties with the United States (300 MW) and British Columbia (1300 MW); the low transmission case (650 MW intertie capacity between Alberta and BC) is not illustrated in the table. Notice that the optimal generating mix with no carbon tax has less coal than the existing mix. This is because developments in anticipation of future growth and the need for backup reserves are not taken into account in this exercise.

Table 4: Optimal Generating Capacities, Various Scenarios, MW

Item	Nuclear	Coal	CCGT[a]	OCGT[a]	Wind
Initial	0	6550	3800	1500	805
No trade between Alberta and BC					
\$0	0	4536	3800	1500	805
\$50	0	0	7550	2290	805
\$100	0	0	8020	1820	805
\$150	0	0	7980	1855	6365
\$200	0	0	8075	1765	11,380
\$150(Nuke)	5945	0	3800	90	805
\$200(Nuke)	6910	0	3015	0	805
Alberta-BC trade along 1300MW-capacity transmission intertie					
\$0	0	4100	3800	1500	805
\$50	0	0	7565	1500	805
\$100	0	0	7970	265	805
\$150	0	0	6370	1865	9940
\$200	0	0	6630	1605	11,500
\$150(Nuke)	2810	0	3800	1630	805
\$200(Nuke)	6330	0	1965	0	805

[a] CCGT and OCGT refer to base-load and peak-load facilities, respectively.

In the table, the carbon tax increases in \$50/tCO_2 increments. Coal is driven out of the generating mix even at a low tax of \$25/tCO_2, but that is only because gas plants are relatively cheap to build and operate because of low fuel costs.[3] Once the carbon tax is taken into account, CCGT plants and even OCGT plants operate at a lower cost than coal plants, and that is mainly due to declining gas prices as a result of unconventional gas finds. In the no trade situation, total natural gas capacity rises to 9840 MW (although its composition between CCGT and OCGT changes slightly as a result of different starting points in the solver's search algorithm). There is no increase in wind capacity until the carbon tax reaches \$150/tCO_2; then the number of wind turbines increases from 350 to nearly 2800, and then to almost 5000 as the tax goes to \$200/tCO_2. However, there is no reduction in installed gas generating capacity as gas is needed to backstop unreliable wind power. However, when nuclear power is permitted in the generation mix, wind no longer comes into the mix at carbon taxes of \$150/tCO_2 or more, while natural gas capacity falls. Nonetheless, natural gas plants are necessary; at a tax of \$200/tCO_2 the increase in nuclear capacity no longer replaces natural gas capacity one-for-one as it did when the tax was \$150/tCO_2. This is because natural gas plants can ramp up and down much faster than nuclear plants, and this ramping ability is required to track swings in net load, which are somewhat aggravated by the remaining wind in the system (see Figure 1).

A similar story can be told when Alberta is able to trade energy with British Columbia. In this case, however, 1600 MW of installed gas plant capacity can be shed in exchange for 3575 MW of extra wind capacity in the \$150/tCO_2-tax scenario. Interestingly, for the \$200/tCO_2-tax scenario, 10,695 MW extra wind capacity is installed, but only 1600 MW of gas capacity is

[3] If the gas price is increased to levels seen early in the 2000s, then coal is not driven out of the mix at a tax of \$25/tCO_2, although coal disappears once the tax hits \$50/tCO_2.

shed.[4] Hydro resources in British Columbia and natural gas are needed to backstop erratic wind power output, but reliance on the former is limited by the transmission constraint (and potentially hydroelectric operating constraints).

Next consider the profile of annual generation. This is provided in Figure 2 for all three scenarios and various levels of the carbon tax. The impact of the intertie is limited because the maximum amount of energy that can be transmitted annually along a high-capacity Alberta-BC intertie is only 11,388 GWh (i.e., for the scenario in panel c of the figure) and that includes flows in both directions (so the contribution to generation in Alberta will be much lower). Therefore, the story is much the same across the three panels of Figure 2, and supports the observations noted in the previous paragraphs. When nuclear power is excluded, installed wind generating capacity and output will increase, but natural gas is still required to backstop intermittent wind. This is only mitigated somewhat as the capacity of the intertie is increased. Clearly, the natural variability of wind severely constrains its contribution to the Alberta electrical grid.

When nuclear energy is allowed to enter the grid, it enters at a lower carbon tax than wind, namely, at \$125/tCO_2 rather than \$150/tCO_2, although both are very high thresholds given that the price of carbon on the European exchange in early 2012 was less than \$20/tCO_2. Nonetheless, the contribution of gas to annual generation is much lower when nuclear plants are present than with optimally-determined wind capacity. Further, as the Alberta system is increasingly allowed to import to or export from British Columbia, the need for natural gas declines, but it does not disappear altogether. What is happening?

[4] There is a 5000-turbine limit in the model so that only 11,500 MW can ever be installed.

Figure 2: Annual Generation by Asset Type, Various Scenarios and Taxes, GWh

In effect, nuclear power plants can ramp only very slowly. Thus, BC hydro reservoirs act as a large battery that stores energy when nuclear power output exceeds net Alberta load and draws it down when the net load exceeds nuclear output. Of course, the small hydroelectric storage capacity that does exist in Alberta (as well as the intertie to the U.S.) also facilitates this function. The contribution of gas plants is limited to situations where this operational imperative is constrained. This is evident in Figure 2.

Finally, we can look at the annual level of exports and imports along the Alberta-BC intertie. In the model, these are driven by the differences in prices between Alberta and BC. While the BC price is fixed in every hour at $75/MWh (and there is a small transmission cost), average hourly prices in Alberta fluctuate, as indicated in Figure 3 for different seasons during the year. Not unexpectedly, there is a spike in prices during peak hours, most notably between 8 a.m. and 10 a.m. and again in the late evening. This pattern is primarily the result of electricity demand for lighting and entertainment, as opposed to heating. Given the fixed BC price, it is clear that, for much of the day, Alberta will export to BC, at least until the carbon tax raises Alberta production costs to the point where it pays to import power from BC. In practice, however, the BC system operator, BC Hydro, will employ different prices throughout the day to maximize the rents from exchange with Alberta, but the current model does not take this into account. This then explains some of the results that follow.

Alberta's total annual exports and imports of power to British Columbia are provided in Figure 4. As the carbon tax rises and more wind or nuclear enters into the Alberta mix, the province goes from being a major exporter of power to British Columbia to a major importer.

The main reason is that the carbon tax applies to exports of Alberta's fossil fuel generated power but does not apply to carbon-free imports of hydropower from BC.

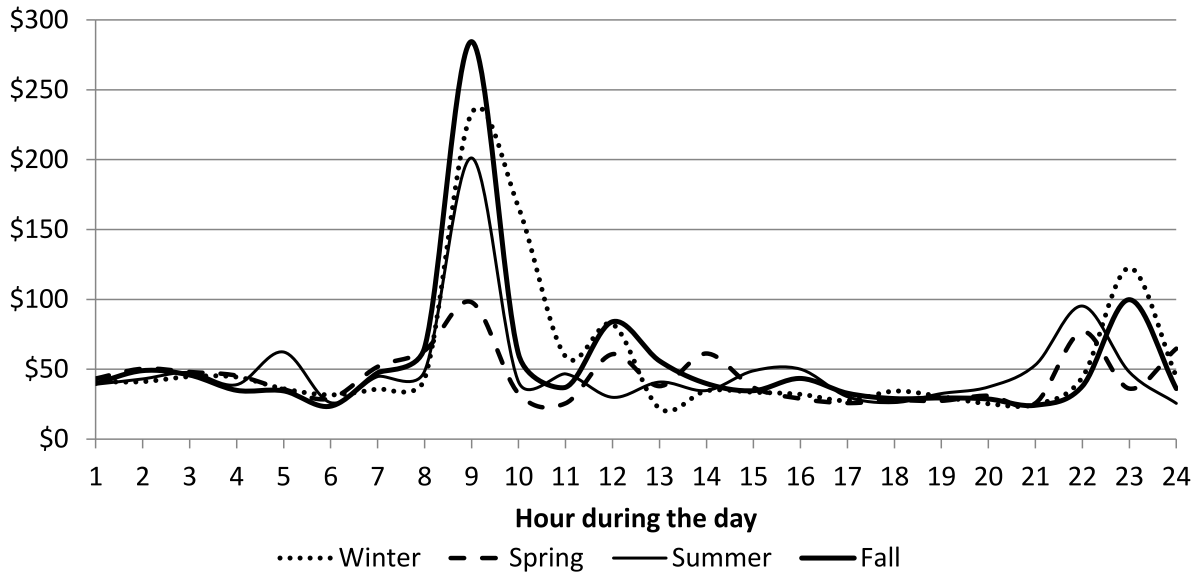

Figure 3: Average Hourly Alberta Prices ($/MWh), Various Seasons, 2010

Further, despite large amounts of variable wind power generation at higher carbon taxes, there remains significant gas output (Figure 2). When there is a drop in wind generation, the increase in net load is better met by imports from BC, while, if there is an increase in wind generation, the reduction in net load is best met by backing off natural gas power output. The same is true in the case where nuclear power is dominant – there is still sufficient gas generation in the system (≥1965 MW of capacity) that can be used to cover reductions in net load that cannot be covered by ramping nuclear plants, with imports and gas (in that order) covering any shortfall. In this regard, it is important to remember that the capacity of the intertie represents 17.5% at low capacity and 35.1% at high capacity of the difference between annual peak and minimum load in Alberta (Table 1).

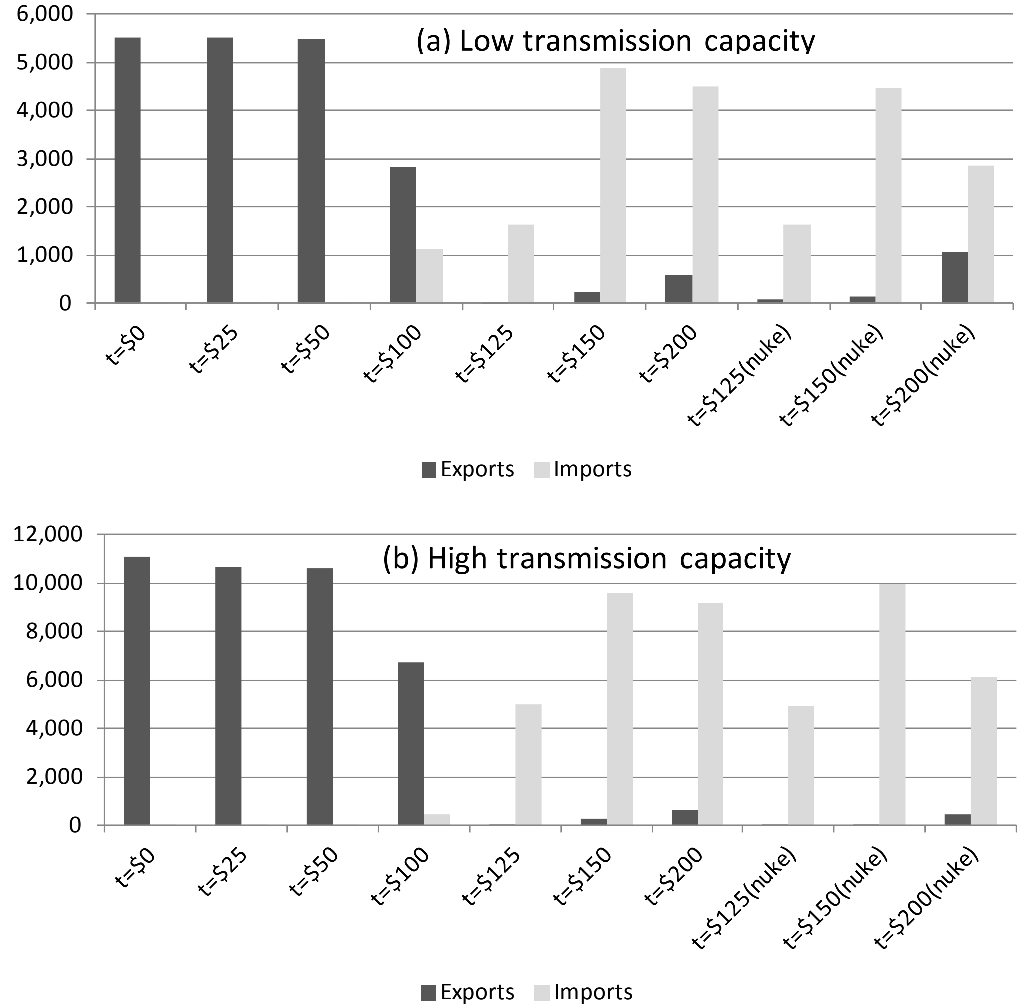

Figure 3: Exports and Imports along the Alberta-BC Intertie for Transmission Capacities of 650 MW (panel a) and 1300 MW (panel b), Various Scenarios and Carbon Taxes, GWh

Reducing Carbon Dioxide Emissions

Emissions of carbon dioxide for each of the scenarios in the model are provided in Table 5. Base-line (carbon tax = 0) emissions for the three transmission scenarios vary by nearly 10 percent, whereas one might have expected them to be equivalent or decline with increased intertie capacity. As is evident from the prices in Table 1, trade between Alberta and the U.S. is one-sided – Alberta always imports power because its prices are invariably higher than those of the Mid-C trading hub, plus there is no carbon tax in the model on imported power. The capacity of the Alberta-MidC intertie is not varied across scenarios, although imports do fluctuate slightly from one scenario to another.

Imports from the U.S. and from BC lower Alberta's greenhouse gas emissions, while exports to BC increase them. Compared to the case of no connection between jurisdictions, when the capacity of the Alberta-BC intertie is at 650 MW the reduction in CO_2 emissions from U.S. imports appears to offset the increase in emissions from exports to BC; this is despite the fact that Alberta exports are at their limit. Coal-fired generation is about 9000 GWh higher in the no trade versus low-level trade scenario, as is clear from a comparison of panels (a) and (b) in Figure 2. This is because, while some exports come from wind-generated power, trade appears to facilitate a partial switch from coal plants to low-emissions gas plants even when carbon is not priced. A jump to the higher intertie-capacity scenario doubles exports to BC when the carbon price is zero. However, as indicated in Figure 2(c), the increase in exports from 5694 GWh to 11,388 GWh comes from coal-fired plants leading to an increase in overall emissions, even compared to the no trade scenario. This is seen in Table 5.

Table 5: Total Emissions under Various Scenarios and Carbon Taxes, Mt CO_2

	No Trade		Low intertie capacity		High intertie capacity	
Carbon tax	Wind Only	Wind & Nuclear	Wind Only	Wind & Nuclear	Wind Only	Wind & Nuclear
$0	47.1	47.1	45.1	45.1	49.4	49.4
$25	30.6	30.6	32.0	32.0	34.4	34.4
$50	29.6	29.6	31.3	31.3	34.0	34.0
$100	29.4	29.4	28.9	28.9	30.9	30.9
$125	29.4	20.6	27.5	14.6	26.0	15.4
$150	24.8	7.0	19.2	3.9	16.4	3.7
$200	21.2	3.9	17.7	2.1	15.5	1.7

As the capacity of the Alberta-BC intertie increases from 0 MW to 650 MW and then

1300 MW, respective reductions in CO_2 emissions of 55%, 60% and 68% might be attainable if we rely only wind power. These are significant reductions, but they can be partly attributed to ideal trade conditions, a potentially unacceptable carbon tax, and a huge increase to 5000 wind turbines of 2.3-MW capacity across the southern Alberta landscape (see McWilliam et al. 2012). Further, such savings occur in a system that is currently heavily reliant on fossil-fuel generation, especially coal – it is like picking low-hanging fruit. What is most surprising, however, is that carbon dioxide emissions in Alberta's electricity sector can be reduced by an incredible 90 percent or more if large investments in nuclear energy were forthcoming.

Finally, the costs of reducing CO_2 emissions are provided in Figure 5. Although the availability of substantial intertie capacity (1300 MW) between Alberta and BC lowers the costs of reducing greenhouse gas emissions (compare thick solid and dashed lines, thin solid and dashed lines), the shift from wind to nuclear power (thick versus thin solid lines, thick versus thin dashed lines) leads to much greater 'bang for the buck' – the same tax moves one closer to the carbon free objective.

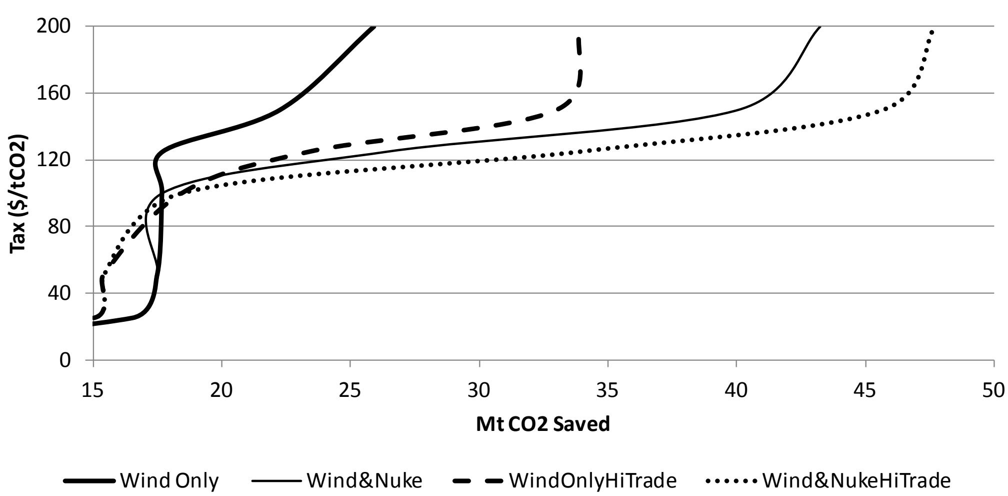

Figure 5: Average Costs of Reducing CO_2 Emissions, Wind vs Nuclear and No Trade vs High Capacity Intertie

Wasted Renewables

One of the most pernicious objections to the integration of carbon-free renewable sources of energy into an electrical grid is the potential that renewable energy of one form simply replaces renewable energy of another form, leading to 'wasted' renewable energy. For example, if wind energy displaces run-of-river hydroelectric energy elsewhere in the system, then the hydropower not produced constitutes a wasted renewable. One also wastes renewable energy if nuclear power is dispatched to another jurisdiction, but it results in the displacement of wind power in that jurisdiction.

There are other instances of waste. For example, renewable energy is essentially wasted if it fails to displace output from a fossil fuel plant one for one. This might occur if a coal-fired power plant cannot reduce output quick enough to follow a decline in net load caused by increased power from the system's wind farms. In this case the wind energy is not really needed, and thus considered wasted. Measuring the extent of wasted renewables is difficult.

In Table 6, we provide some indication of the magnitude of wasted renewable in the first sense – the extent to which one renewable energy source displaces an equal amount of power generated by another renewable source. This is done by comparing the hydroelectric energy that the Alberta system could potentially produce with what it actually does produce. Total system demand is about 68,000 GWh. As indicated in the table, when the carbon tax is less than about \$100/tCO_2, wasted renewables are negligible. Even when no trade occurs, wasted renewables amount to only 0.5% by our measure, and become negligible as the intertie capacity increases. This conclusion may, however, be an artifact of the system that we model. Alberta has little in the way of renewable generating capacity, so little indeed that the effect of the current 7% wind penetration makes little difference to the operation of the system. Likewise, hydro capacity is small and is little impacted by the variability in wind. In this model, therefore, wasted renewables are not a problem and they are unlikely to be one until wind penetration rises to 20 percent or more (Lund 2005).

Table 6: A Measure of Potential Wasted Renewables as a Result of Integrating Carbon-free Generating Assets into an Electrical Grid, GWh

	No Alberta-BC trade		Low capacity intertie		High capacity intertie	
Carbon tax	Wind Only	Wind & Nuclear	Wind Only	Wind & Nuclear	Wind Only	Wind & Nuclear
$0	7.40	7.40	8.36	8.36	6.96	6.96
$25	0.65	0.65	0.69	0.69	1.19	1.19
$50	0.62	0.62	0.65	0.65	0.75	0.75
$100	0.63	0.63	0.46	0.46	0.46	0.46
$125	0.63	1.79	0.46	0.46	0.46	0.46
$150	71.86	144.56	26.10	1.26	5.12	0.44
$200	303.03	421.72	100.35	58.78	30.89	0.35

Concluding Discussion

In an attempt to reduce CO_2 emissions from the generation of electricity, many governments are considering implementing economic incentives, whether a carbon tax or a cap-and-trade scheme. With the generating mixes of many electrical grids dominated by fossil fuels, this will result in either a substantial increase in the cost of generation or a significant transformation to other, lower CO_2 emitting technologies. Generation of power from hydroelectric dams, wind turbines and nuclear power plants may be seen as viable alternatives.

A carbon tax on power generation in Alberta clearly leads to increased reliance on lower CO_2-emitting sources of energy for generating electricity, especially greater reliance on natural gas in lieu of coal. Only when the carbon tax exceeds about $100/t$CO_2$ does an optimal generation mix rely on a great deal of wind energy instead of natural gas. Yet, at a very high carbon tax, natural gas capacity increases over what it would be in the absence of wind because gas plants are needed to backup intermittent wind resources. Thus, while the amount of electricity generated from natural gas may fall with increasing wind penetration, gas plant capacity must be increased.

When nuclear power is permitted to enter the generating mix, it replaces wind almost entirely. This is the case even though the upfront costs of building nuclear capacity are extremely high. Compared to wind-generated power, there are significant savings with nuclear power from not having to build gas plant capacity alongside wind. This cost difference is often ignored in studies of nuclear energy.

It is frequently assumed that high-voltage transmission interties are the answer to intermittent wind energy. However, the results in this study suggest that natural gas and gas prices play a much larger role in facilitating intermittent (wind and solar) energy than does added transmission capacity. Alberta has pursued a policy of adding to CCGT and OCGT capacity. This appears to be a very reasonable response to increased wind-power generating capacity, especially if BC is unwilling to share economic rents from storing intermittent energy.

While high-capacity interties provide some benefit, these do not appear to be as large as originally expected. Further, adding transmission lines or increasing capacity of existing lines is expensive, and that was something not taken into account here.

In the current research, the greatest CO_2 emission-reduction benefits come from an ability to substitute carbon-free nuclear energy for fossil fuels. However, the transition to nuclear energy is unlikely to be straightforward because the carbon tax is not about to be raised to \$150/tCO_2 or higher in the very near future. Rather, the transition will likely take the form of a progression from a coal-natural gas mix to reliance solely on natural gas for generation and, finally, to nuclear energy – a natural gas to nuclear (N2N) transition. Along the line, wind penetration may well increase, but mainly due to subsidies or the result of regulatory impediments to nuclear power. Nonetheless, the results of this study provide support to proponents of a N2N progression for drastically reducing CO_2 emissions.

A number of issues have not been addressed in our model. One is that British Columbia may not have the ability to export unlimited energy to Alberta, as BC may need to enhance its hydroelectric and other generating capacity to meet load in the near future (see Sopinka and van Kooten 2012). To account for this aspect would require inclusion of a BC model with some details regarding the operation of its hydroelectric facilities – water storage and changes in generating capacity as reservoir levels vary.

In addition, as greater wind energy enters the system, prices will undoubtedly change. Likewise, BC prices cannot be assumed fixed at every hour, but will vary according to load and opportunities for the system operator, BC Hydro, to maximize rents. In the current research, no effort was made to model the impact of increased wind output on prices, as wind would likely bid into the merit order at zero price (van Kooten 2012), nor was the BC price response modeled. These are left to future research.

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APPENDIX: Additional Information

It would appear that, under the Government of Canada's (2011) regulation for generating electricity from coal-fired power plants, the performance standard is an emissions intensity level commensurate with that for combined-cycle natural gas turbine (CCGT) generation, or 375 tCO_2 per GWh of energy. The standard applies to combustion of coal and its derivatives, and "from all fuels burned in conjunction with coal, except for biomass." This leaves open the option of blending biomass to the point where the standard is met.

The following is a table that is based on information from the U.S. Energy Information Administration (2012) that was used to derive fuel prices used in the model.

Table A1: Fuel Prices for Coal and Natural Gas[a]

	Region			
	Mountain		Pacific	
Year	$/mil btu	$/MWh	$/mil btu	$/MWh
Natural gas				
2010	$4.09	$13.97	$4.11	$14.03
2011	$5.08	$17.35	$4.85	$16.56
Coal				
2010	$1.59	$5.43	$2.30	$7.85
2011	$1.72	$5.87	$2.20	$7.51

[a] Coal and CCGT gas prices for Mountain region for December 2010 (respectively, $1.59 and $4.09 per million btu) are multiplied by 3.41442594972 to convert to $/MWh; Pacific region gas price of $4.11/mil btu is used for OCGT. Data are from U.S. Energy Information Administration (2012, p.106).

Trading hub prices can be found at: http://205.254.135.7/electricity/wholesale/