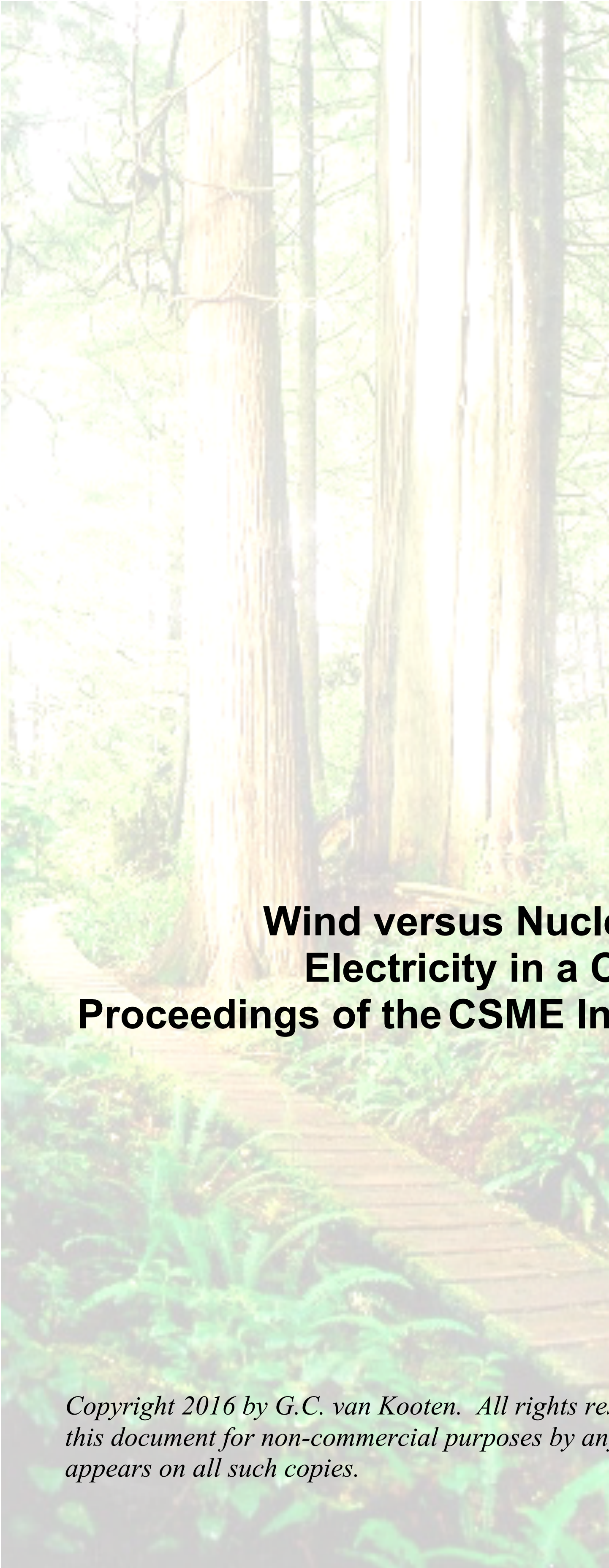

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Wind versus Nuclear Options for Generating Electricity in a Carbon Constrained World: Proceedings of the CSME International Congress 2016

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June 2016

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Proceedings of The Canadian Society for Mechanical Engineering International Congress 2016
CSME International Congress 2016
June 26-29, 2016, Kelowna, BC, Canada

Wind versus Nuclear Options for Generating Electricity in a Carbon Constrained World

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***Abstract*— A mathematical programming model is used to examine the impact of carbon taxes on the optimal generation mix in Alberta's electrical system. The model permits decommissioning of generating assets with high CO_2 emissions and investment in new gas, wind and, in some scenarios, nuclear capacity. Although there are interties between Alberta and the U.S. and Saskatchewan, the focus is on the one to British Columbia, as wind energy can potentially be stored in reservoirs behind hydroelectric dams. Storage can also smooth out the net load facing nuclear facilities. In the model, 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 \$80/tCO_2 that wind enters the system, although wind is displaced by nuclear power if that option is permitted. Despite high upfront costs, nuclear outcompetes wind primarily because wind requires a great deal of gas capacity that is not needed with nuclear energy. While wind alone could lower CO_2 emissions by two-thirds, nuclear can reduce them by more than 90%.

Keywords- climate change, renewable energy, transmission capacity, energy storage

I. INTRODUCTION

A carbon tax is viewed by many as an economically efficient means to eliminate coal-fired power generation and promote investments in renewable generating sources, such as wind and solar, and possibly nuclear energy. Along with growing demand for electricity and a desire to reduce greenhouse gas emissions, there has been renewed discussion about the role nuclear power might need to play in meeting emission reduction targets. However, 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 a great deal, 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) 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 [1]. The need for fast ramping technologies is magnified when there is inadequate transmission capacity [2]. However, an ability to store intermittent wind-generated power behind hydroelectric dams, which are 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 [3] recommends that, if significant reductions in global CO_2 emissions are needed to stabilize the climate, installed nuclear capacity in the U.S. will need to increase from the current 100 GW to 300 GW by 2050 and from 340 GW to 1,000 GW globally. Despite finding that nuclear power could be competitive with coal and natural gas, the MIT study found that their target was far from being realized. Other studies have also recommended that nuclear power will be needed if carbon emission reduction targets are ever to be met (e.g., [4]; [5]).

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. These costs are likely to be small [6]. However, 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 [3]. 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 intertie. 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 hydro, biomass and 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), the Mid-Columbia (MidC) region in the U.S., and Saskatchewan; (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, MidC and Saskatchewan grids. The model builds upon earlier work by [7], [8] and [9].

II. 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 [8] show, these benefits are enhanced by trading power with BC where storage behind hydroelectric dams is possible. 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), Saskatchewan and British Columbia; this decision is based on the prices in the various jurisdictions and transmission line capacities (discussed below). The authority also decides on the decommissioning of extant fossil-fuel generation assets and investment in new (wind, nuclear) 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 AESO profit function can be written as follows:

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

where Π is profit (\$); i refers to the generation source (viz., natural gas, coal, nuclear, wind, hydro) in Alberta; T is the number of hours in the one-year time horizon (8760); Dt refers to be the demand or load that has to be met in hour t (MW); Qti is the amount of electricity produced by generator i in hour t (MW); OMi 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 Pj,t to be the price (\$/MWh) of electricity in each hour, with $j \in$ {AB, BC, MID, Sask} referring to Alberta, British Columbia, MidC and Saskatchewan, respectively. While Alberta and MidC prices vary hourly, the BC and Saskatchewan prices are fixed at \$75 and \$56 per MWh, respectively. Mk,t refers to the amount imported by Alberta from region $k \in$ {BC, MID, Sask} 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'), storage is assumed to be available in each period in neighboring jurisdictions via transmission interties; excess energy can be directed or retrieved if the Alberta 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_{kt} and TRX_{kt}, respectively, with k defined above and capacity changing over time for reasons discussed below. 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,

[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 Alberta's northern location.

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:

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

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

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

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

Import trans constraint:
$$M_{k,t} \leq TRM_{k,t}, \ \forall\ k,t \tag{6}$$

Export trans constraint:
$$M_{k,t} \leq TRK_{k,t}, \ \forall\ k,t \tag{7}$$

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

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 $TRM_{k,t} = TRX_{k,t} = TCAP_{k,t}, \forall k$, 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:

$$X_{k,t} + M_{k,t} \leqslant TCAP_{k,t}, \ \forall\ k,t. \tag{9}$$

Some 1,200 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 as must run (and subtracted from load).

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.

III. Data

The Alberta electricity grid had 6,258 megawatts (MW) of coal capacity, 6,600 MW of natural gas-fired capacity, 545 MW of biomass generation, 900 MW of hydroelectric capacity and 1,286 MW of wind capacity [10]. Hydropower is best consider non-dispatchable or 'must run', so generation depends on river flows and other uses of water. Natural gas is used in open-cycle gas turbine (OCGT) plants to provide fast-ramping, peak load power; it is also used in base-load, combined-cycle gas turbine (CCGT) plants and co-gen plants that produce heat and power. Using [10] data on generation additions since 1998, it is estimated that there exists 4,008 MW of co-gen capacity, while the remaining gas capacity of 2,592 MW capacity is divided approximately evenly among the OCGT and CCGT types. Alberta has also installed 1,068 MW of coal-fired capacity since 2005.

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.

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 Fig. 1 where Alberta load and wind-adjusted load for the first ten days in January 2014, and the last ten days in December 2014, are provided in ten-minute intervals. During 2014, installed wind capacity rose from 1,112 MW to 1,459 MW, or by 31.2%. Not surprisingly, the wind-adjusted load in the beginning of 2014 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 2014 (Fig. 1b) than it is at the beginning (Fig. 1a). As wind penetration increases, existing coal and some natural gas assets have more difficulty following the wind-adjusted load than the normal load.

TABLE 1: LOAD AND PRICE DATA USED IN MODEL, 2014

	Alberta	BC	Mid-Col	Sask
Load (MW)				
Average	9,128	7,061	-	2,671
Maximum	11,169	10,672	-	3,561
Minimum	7,162	4,817	-	1,854
Energy Price ($/MW)				
Average	49.50	75	56	50
Maximum	999.99	-	127	
Minimum	7.88	-	0	

[a] Source: System operator websites

It is important to note that there are extended periods when winds are weak and very little wind power comes onto the grid. At the beginning of 2014, for example, there was no wind during the first 4½ hours of the New Year, followed by a weak wind regime until 8 am on January 1. Winds were very weak from about 4 am on January 5 until 9 pm that evening, and again through the morning and afternoon of January 7. 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 347 additional MW of capacity were available: wind power output collapsed early on December 25 and, with the exception of a short period early on the 26th, did not pick up again until December 27 (Fig. 1b).

In addition to the above information (load, prices, transmission constraints, wind output), the model takes into account some run-of-river hydropower (produced by a series of dams on the Bow River) and output from biomass and waste facilities. These assets account for an average 360 MW of electricity per hour that ranges from 193 to 767 MW.

Finally, information on construction and operating costs, emissions and ramping rates for generators 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.

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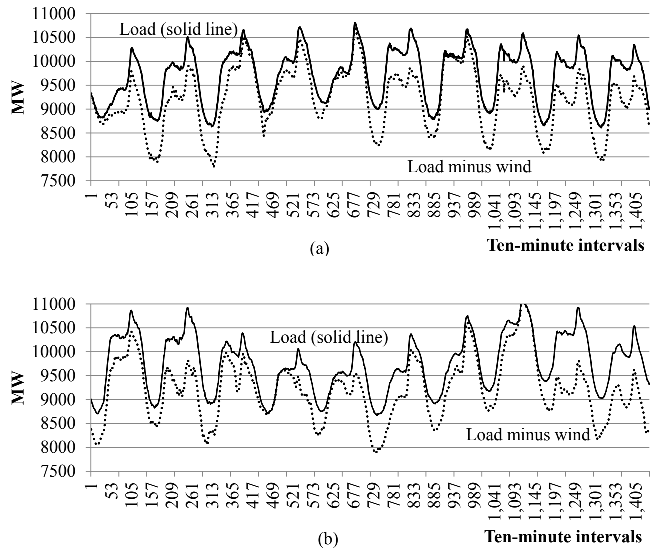

Figure 1: Alberta Load and Wind Generation at 10-minute Intervals, First 10 Days in 2014 (panel a) and Last 10 Days in 2014 (panel b)

Reference [11] estimates the system ramping rate to be around 100 MW per 10 minutes, although they vary by asset. The majority of coal and gas plants cannot ramp any faster than 5 MW per 10 minutes. Ramp rates for different sorts of assets in the last column of Table 2 have been calculated on an hourly basis and as a percent of capacity.

IV. MODEL RESULTS

At COP-21 in Paris in December 2015, Canada stated that it "intends to achieve an economy-wide target to reduce our greenhouse gas emissions by 30% below 2005 levels by 2030." One of its strategies for achieving this target is to ban construction of new coal-fired power plants and phase out existing plants. Federal government regulations would require 12 of 18 of Alberta's coal plants to close by 2030, but the province intends to close all coal plants by 2030 [12]. The Alberta government is hoping to replace two-thirds of coal-fired electricity with renewables (mainly wind), which are to account for 30% of electricity production by 2030. To that end, the province is also implementing a carbon tax that starts at $20/tCO_2$ in 2017 and rises to $30/tCO_2$ in 2018.

To better understand how Alberta's optimal generating mix might respond to climate mitigation policies that aim to achieve these targets, and whether the target to remove coal generation and replace it with wind 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 the current and double-current transmission capacities 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 to achieve a 80% reduction in emissions by 2050 as called for by the G8 countries in 2009, and adopted by California for example [4]. 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.

The model results are provided in Table 3. In the base case, and because a linear programming model is employed, the lowest-cost source of power is always chosen subject to the model constraints. Baseload plants operate at or near capacity throughout the year, and the intertie is only used sparingly in the model as Alberta attempts to avoid high-priced power from BC. In practice, the intertie between the provinces is used more frequently than indicated: In 2013, transmission from Alberta to BC was limited to an average capacity of 298 MW per hour (range 0 to 899 MW) due to AESO operating constraints, while trade in the other direction was limited to 576 MW per hour (range 0 to 790 MW) depending on the hour [13]. Alberta experienced actual average net imports of 189 MW per hour, and there was little trade in the other direction. Although not shown here, modeled exports and imports to the U.S. and Saskatchewan varied considerably throughout the year according to price differences; this corresponded closer to actual trade.

In the base case, the electricity system would generate an operating profit of some \$36.6 billion annually, which would then be used to fund new investment and reserve capacity. With a carbon tax, operating profits (which include the tax revenue but do not include the cost of decommissioning capacity) fall because less efficient sources of power generation are employed as compared to the base case.

A. Capacity and Generation.

Consider first the case where government uses a carbon tax to incentivize investment in wind power capacity. The impact of the carbon tax on an optimal generation mix is found in the last three columns of Table 3. For taxes of \$30/tCO_2 (to be imposed in 2017) to about \$80/tCO_2, little changes since no additional wind capacity is introduced and no coal plants are decommissioned. Because uncertainty is not explicitly modeled, peak gas plants are decommissioned as these are the most expensive to operate (although retained in practice to protect against unforeseen loss of power). Once the carbon tax exceeds \$80/tCO_2 wind enters the optimal generation mix.

The province abandons coal with a carbon tax of \$100/tCO_2, replacing it with wind and, importantly, additional gas. For each MW of new wind capacity installed, 0.22 MW of gas is installed. It is not until an even higher carbon tax (\$200/tCO_2) that it is optimal to build the maximum number of turbines permitted in the model (6,000 turbines of 2.3 MW capacity).

With 6,000 wind turbines, even more gas capacity is needed: at the margin, for every additional MW of wind power that is installed, 0.69 MW of gas capacity needs to be built. This result is similar to that of [18], who found that 0.7-0.8 MW of gas is required as backup for every 1 MW of wind power capacity.

TABLE 2: CAPITAL AND VARIABLE COSTS (US\$2012), CO_2 EMISSIONS, AND RAMP RATES OF VARIOUS GENERATING ASSETS

		Capital Costs		Variable Costs			
Asset	Yr[a]	Over-night cost (\$/kW)	Fix O&M \$ per kW-y	O&M \$/MWh	Fuel \$/MWh	tCO_2 / MWh	Ramp rate: % of cap
Nuke	7	8,000	85	2.14	7.70	0	2.0
Bio	3	4,300	120	5.26	92.70	0.302	2.5
Coal	4	3,700	35	4.47	5.43	0.319	2.5
Wind	2	2,000	30	0	0	0	n.a.
Hydro	5	3,200	30	0	1.01	0	n.a.
CCGT	3	1,300	10	7.22	18.95	0.181	10.0
OCGT	2	1,200	10	10.37	18.95	0.181	50.0
Cogen	3.5	1,650	10	10.50	22.63	0.187	2.5

[a] Number of years to build asset.
Sources: [14]; [15]; [16]; [17].

TABLE 3: RESULTS

		AB to/from BC (GWh)		Optimal capacity (MW)		
Scen-arios	Mt CO_2	Import	Export	Coal	Gas	Nuclear
Base	68.8	0	2,610	6,258	2,592	0
Current transmission capacity: No nuclear						
\$30	65.1	1	2,609	6,258	2,592	0
\$100	26.7	4,225	202	0	5,106	0
\$200	25.1	4,520	152	0	5,885	0
Current transmission capacity: With nuclear						
\$100	4.2	3,373	349	0	1,186	7,233
\$200	2.0	1,908	1,536	0	276	8,136
Double transmission capacity: No nuclear						
\$100	23.4	8,493	230	0	4,737	0
\$200	22.4	9,035	163	0	5,321	0
Double transmission capacity: With nuclear						
\$100	3.0	6,621	245	0	710	7,086
\$200	1.7	3,697	1,394	0	195	7,862

Source: Author calculations

The model generates power first from least-cost coal followed by CCGT gas and then co-gen. When the tax makes coal too expensive, wind assets are built and remaining non-wind load is met from CCGT, co-gen and imports. Trade is incentivized by price differences, but the high carbon taxes used in the analysis exceed price differences among the four jurisdictions. Imports from BC increase from nearly zero to over 4,000 GWh at the same time that exports decline by more than 2,400 GWh. Imports from the U.S. and Saskatchewan are maximized (constrained only by intertie capacities). This is because imports are not taxed while Alberta exports could be taxed depending on their source. There is an overall decline in total production of electricity in Alberta by about 6,000 GWh per year as a result of high carbon taxes.

If the current capacities of the interties between BC and Alberta are doubled, Alberta imports of BC hydropower double as it is not taxed (Table 3). Alberta produces some 17,500 GWh less electricity under a \$200/tCO_2 tax than in the base case. Since the tax does not affect load, the difference must be met solely by changes in net imports.

B. Nuclear Energy

Nuclear energy changes everything. The nuclear option eliminates the need for wind power despite its high cost. The reason is that, unlike with wind energy, it is unnecessary to build additional gas plant capacity (Table 3). To avoid the carbon tax, 90% or more of electricity will be generated by nuclear plants. Although nuclear power plants have little ability to ramp their production, available storage in other jurisdictions enables nuclear capacity to exceed base load. When nuclear power exceeds base load, electricity is exported and stored, to be used when load exceeds the capacity of the nuclear assets. The contribution of gas plants is limited to situations where this operational imperative is constrained.

Overall, imports of electricity from other jurisdictions drop by some 25% ($100 tax) to nearly 60% ($200 tax) in the model compared to the case where only wind is permitted. Under the nuclear option no intermittent wind power is required, less power is required from gas sources and, consequently, less carbon free imports are needed because nuclear power is carbon free and reliable.

C. Reducing Carbon Dioxide Emissions

Emissions of carbon dioxide for each of the scenarios in the model are also provided in Table 3. A tax of $30/tCO_2$ will reduce Alberta emissions from power generation by only 5.5%. A very high carbon tax of $200/tCO_2$ has the potential to reduce emissions by 63.5% assuming current intertie capacities and by 67.4% with double-current intertie capacities. However, average costs of reducing emissions range from $253 to $857 per tCO_2, depending on the scenario.

Again, the nuclear option changes everything: Emissions can be reduced by between 94.0% and 97.5% depending on the intertie capacities – a finding similar to that for California [4]; [5]. Meanwhile, the cost of reducing emissions now ranges from about $193 to $200 per tCO_2.

V. Concluding Discussion

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 tax exceeds about $100/tCO_2$ does an optimal generation mix rely on a great deal of wind energy instead of natural gas. Yet, at a very high tax, gas capacity increases over what it would be in the absence of wind because gas plants are needed to backstop intermittent wind resources.

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 will play a much larger role in facilitating intermittent wind energy than does added transmission capacity. 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.

Acknowledgment

The author acknowledges support from NSERC and CRC. He also wishes to thank Ged Mclean for helpful comments.

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