Wind versus Nuclear Options for Generating Electricity in a Carbon Constrained World: Strategizing in an Energy Rich Economy

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A carbon tax is an economically efficient means to incentivize carbon-reducing investments in electrical generating systems. Along with growing demand for electricity and a desire to mitigate climate change, there has been renewed discussion about the role of nuclear power in meeting CO_2 emission reduction targets. However, recent concern about the failure of Japan's Fukushima Daiichi nuclear plant has reduced society's already low confidence in nuclear power. Thus, renewable sources of energy generation, such as wind, are seen as better alternatives to fossil fuels for reducing CO_2 emissions.

Increasing reliance on wind generation poses challenges for electrical system operators because of the variable nature of wind, lack of storage, need for backup generation, transmission constraints and costs of building additional transmission capacity. 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; CO_2 emissions from these plants are higher than usual due to operation at

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less than optimal capacity and more frequent starts and stops (Prescott and van Kooten 2009). The need for fast ramping technologies is magnified when there is inadequate transmission capacity (Maddaloni, Rowe and van Kooten 2008). An ability to store wind-generated power behind hydroelectric dams, which are also relatively fast ramping, can compensate for its intermittency. Nuclear power plants 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. Therefore, they are competitive with coal and natural gas.

Both wind and nuclear energy have drawbacks, but in this paper, we focus solely on the externality associated with CO_2 emissions. In this way, we can examine optimal investment in generating assets in response to market incentives that increasingly penalize fossil fuel electricity production. We use the Alberta electricity system as our case study because it has a high proportion of fossil fuel assets that can be removed to reduce CO_2 emissions. Additionally, the potential to link to British Columbia (BC) offers the opportunity to store variable wind power behind the large-scale hydroelectric assets that characterize its electrical system. In response to increasing demand 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 viable options for Alberta.

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 Alberta and BC (where variable wind energy can be stored); (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.

Methods

To assess these objectives, a mathematical programming model is developed for the Alberta electricity grid with links to BC and the U.S. We extend an earlier model by Scorah, Sopinka and van Kooten (2012) to include trade with the U.S. Pacific Northwest (Mid-Columbia or MidC) region, using price differentials to incentivize trade. In addition, we use a carbon tax to promote decommissioning of fossil fuel assets and investment in wind farms and/or nuclear facilities that have little or no emissions.

Alberta’s power system is completely deregulated, with the Alberta Electric System Operator (AESO) using prices and knowledge about load and power output to allocate generation across assets. The AESO also chooses to import or export electricity across interties to the U.S. (MidC) and BC based on price differentials and transmission line capacities (discussed below). Finally, the authority is assumed to decide on the decommissioning of extant fossil-fuel generation assets and investment in new (wind, nuclear or alternative fossil-fuel) assets. The AESO is assumed to maximize annual profit subject to load, trade and engineering constraints. The profit function is as follows:

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

where Π is profit ($); *i* refers to the generation source (*viz.*, natural gas, coal, nuclear, wind, hydro); T is the number of hours in one-year (8760); D_t refers to the demand or load that has to be met in hour t (MW); $Q_{t,i}$ is the 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. $M_{k,t}$ is the amount imported by Alberta from region $k \in \{BC, MID\}$ at t, while $X_{k,t}$ is the amount exported from Alberta to region k; δ is the transmission cost (\$/MWh).

In addition, C_i refers to the capacity of generator 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 added, each with a capacity of 2.3 MW. Given that wind energy is non-dispatchable (‘must run’), a sink, S_t, is assumed available in each period where excess energy can be directed or retrieved if the system cannot respond quickly enough. Further, R_i is the amount of time it takes to ramp production from plant i. Transmission between jurisdictions is constrained depending on whether power is exported or imported; import and export constraints are denoted TRM_k and TRX_k, respectively. Finally, τ is a carbon tax (\$ per tCO_2), and φ_i is the CO_2 emitted per MWh of electricity from generation source i.

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

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

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

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

(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: $Q_{t,i}, \mathrm{M}_{\mathrm{k,t}}, \mathrm{X}_{\mathrm{k,t}} \geq 0,\ \forall\ t,i,k$

In any given hour, electricity can only flow in one direction along a transmission intertie. To model this and avoid a nonlinear constraint, we assume that $TRM_k = TRX_k = TCAP_k$, $\forall k$, and then employ the following linear constraint to limit the flow 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 non-dispatchable run-of-river output. The remainder is generated by two dams used primarily for flood control. Although their capacity factors are less than 10%, a small subcomponent of the model simulates the operation of a hydro facility so that the system has some capacity to store wind generated electricity by holding back water (although it is not a pumped storage system). A description of the hydroelectric subcomponent is found in Louck, Stedinger and Haith (1981).

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. Generators that are not needed are removed, although decommissioning of capacity is assumed to be continuous. 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 $Q_{t,i}$, $M_{k,t}$, $X_{k,t}$ 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. For convenience, we treat biomass generation as equivalent to coal. The capacity of the intertie between Alberta and BC varies with direction, but we simply assume a single transmission capacity constraint of 650 MW, doubling it to 1300 MW to examine the impact of potentially greater storage.

BC is dominated by hydroelectricity that accounts for 11,000 MW or 92.4% of BC's 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, which consists of a variety of generating sources that are treated from the Alberta perspective as having zero emissions. Hourly Alberta load data for 2010 are used; in 2010, load averaged 8188 MW per hour, with a peak load of 10,227 MW and minimum (base) load of 6524 MW. Hourly prices for Alberta, MidC and BC are used to determine movements along the interties. In 2010, market clearing electricity prices averaged $90/MWh in Alberta, ranging from a low of $0 to a high of $1000, while those in MidC averaged $56/MWh, with low of $0 and high of $127. The BC system is not de-regulated so prices are unknown; thus we assume a fixed BC price of $75/MWh based on information from contracts with independent power producers and BC Hydro's expected future costs.

If wind power is non-dispatchable and subtracted from load, the remaining generators must ramp up and down to meet this adjusted load. As illustrated in figure 1, the general effect of integrating wind is an increase to the variability of the adjusted load. During 2010, installed wind capacity rose from 501 MW to 715 MW; 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 at the beginning of 2010 (panel a) is impacted less by wind resources than that at the end of the year (panel b). As wind penetration increases, existing coal and natural gas assets have more difficulty following the wind-adjusted load. Finally, there are periods when no wind power is available at all – in figure 1 the longest of these periods lasted 50 hours.

Finally, information on construction and operating costs, emissions and ramping rates for generators are provided in table 1. The cost of installing new generating capacity or decommissioning extant capacity is amortized using a 10% discount rate. Newly built nuclear, coal and gas plants are assumed to last 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 still operate after 40 years.

Model Results

Canada aims to reduce its carbon emissions by 17% (or 124 Mt CO_{2e}) between 2005 and 2020, and by 80% (584 Mt CO_{2e}) by 2050. To understand how Alberta's generating mix might respond to policies that aim to achieve these targets, we employ a carbon tax on emissions that varies from \$0 to \$200 per tCO_2. We investigate scenarios with zero, moderate (650 MW) and high (1300 M) transmission capacity along the Alberta-BC intertie and a scenario where nuclear energy enters the mix with wind. The latter is included to determine if a severe emission reduction target (high carbon tax) could 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 meet the most severe targets.

Capacity and Generation

Consider first the impact of the carbon tax on the optimal generation mix. In table 2, the current generating mix is provided in the first row, followed by results for the case of no trade and then the case where interties exist with the U.S. (300 MW) and BC (1300 MW) – the low 650 MW transmission case is not illustrated. The optimal generating mix with no carbon tax has less coal than the existing mix, because developments in anticipation of future growth and the need for backup reserves are not taken into account in this exercise.

In table 2, the carbon tax drives coal 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 due to low fuel costs. Once the carbon tax is taken into account, CCGT and OCGT plants operate at lower cost than coal. Without trade, total natural gas capacity rises to 9840 MW. 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.

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 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 (figure 1).

When Alberta is able to trade with BC, 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 shed. Hydro resources in BC and natural gas are needed to backstop erratic wind power output, but reliance on the former is limited by the transmission constraint (and potentially operating constraints).

Finally, consider annual exports and imports that are driven by price differences. First, Alberta always imports power from the U.S. because of generally much lower prices at MidC. While the BC price is fixed throughout at \$75/MWh, average hourly prices in Alberta fluctuate (figure 2). 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's production costs to the point where it pays to import power along the Alberta-BC intertie. 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 explains some of the following results.

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 BC 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. Further, despite large variable wind power generation at higher carbon taxes, there remains significant gas output. When there is a drop in wind output, the increase in net load is better met by imports from BC, while, if there is an increase in wind output, 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.

Reducing Carbon Dioxide Emissions

CO_2 emissions for each of the scenarios are provided in table 3. Baseline (tax=0) emissions for the three transmission scenarios vary by nearly 10%, even with increased intertie capacity. Imports from BC and the U.S. 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, even when Alberta exports are at their limit. Coal-fired generation is about 9000 GWh higher in the no trade versus low-level trade scenario 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. With higher intertie capacity, exports to BC double when the tax is zero. However, 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, as seen in table 3.

As the capacity of the Alberta-BC intertie increases from 0 MW to 650 MW and then to 1300 MW, respective reductions in CO_2 emissions of 55%, 60% and 68% might be attainable if wind power is the only alternative to fossil fuels. These are significant reductions, and attributable to ideal trade conditions, a high and unacceptable carbon tax, and a huge increase to 5000 wind turbines in southern Alberta. Further, such savings occur in a system that is heavily reliant on coal generation. What is most surprising, however, is that CO_2 emissions in Alberta's electricity sector can be reduced by a 90% or more if large investments in nuclear energy were forthcoming.

Concluding Discussion

With the generating mixes of most electrical grids dominated by fossil fuels, economic incentives such as a carbon tax or cap-and-trade scheme will lead to a substantial increase in the cost of generation or a significant transformation to lower CO_2 emitting technologies such as hydroelectric dams, wind turbines and nuclear power plants. A carbon tax in Alberta clearly leads to increased reliance on lower CO_2-emitting sources of energy for generating electricity, especially natural gas in lieu of coal. Only when the carbon tax exceeds about \$100/tCO_2 does an optimal generation mix rely on 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.

When nuclear power is permitted to enter the generating mix, it replaces wind almost entirely, even though the 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.

It is frequently assumed that high-voltage transmission interties are the answer to intermittent wind energy, but the results in this study suggest that natural gas and gas prices play a much larger role in facilitating intermittent wind energy than does added transmission capacity. Alberta has pursued a policy of adding natural gas capacity, which 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.

The greatest CO_2 emission-reduction benefits arise from substituting carbon-free nuclear energy for fossil fuels. However, the transition to nuclear energy is unlikely to be straightforward because carbon taxes are not about to be raised to \$150/tCO_2 or higher in the 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 BC may not have the ability to export unlimited hydroelectric energy to Alberta. To account for this requires inclusion of a BC sub-component to the model with details regarding water storage and changes in generating capacity as reservoir levels vary. Further, it will be necessary 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). These are left to future research.

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Table 1: Construction and Operating Costs ($2010), CO_2 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)	% of capacity per hour[c]
Nuclear	7	5400.0	42.8	11.00	7.70	0.020	1.0
Coal	4	1777.0	24.0	6.60	5.43	0.850	2.5
Wind	3	1300.0	n.a.	0.17	0.0	0.015	n.a.
Hydro	4	2100.0	n.a.	3.64	1.01	0.009	n.a.
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

[a] Overnight costs are divided by years to build with the subsequent stream of costs then discounted to the present; data from van Kooten (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 from Northwest Power Planning Council (2002), but inflated to 2010 using the U.S. CPI. Fuel prices for coal and gas are from U.S. Energy Information Administration (2012, p.106). Remaining data are from van Kooten (2012).

[c] Estimates based on AESO (2010, p.13) and total system ramp rate of 600 MW per hour.

Table 2: 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.

Table 3: Total Emissions under Various Scenarios and Carbon Taxes, Mt CO_2

Carbon tax	No Trade Wind Only	No Trade Wind & Nuclear	Low intertie capacity Wind Only	Low intertie capacity Wind & Nuclear	High intertie capacity Wind Only	High intertie capacity Wind & Nuclear
$0	47.1	47.1	45.1	45.1	49.4	49.4
$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
$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

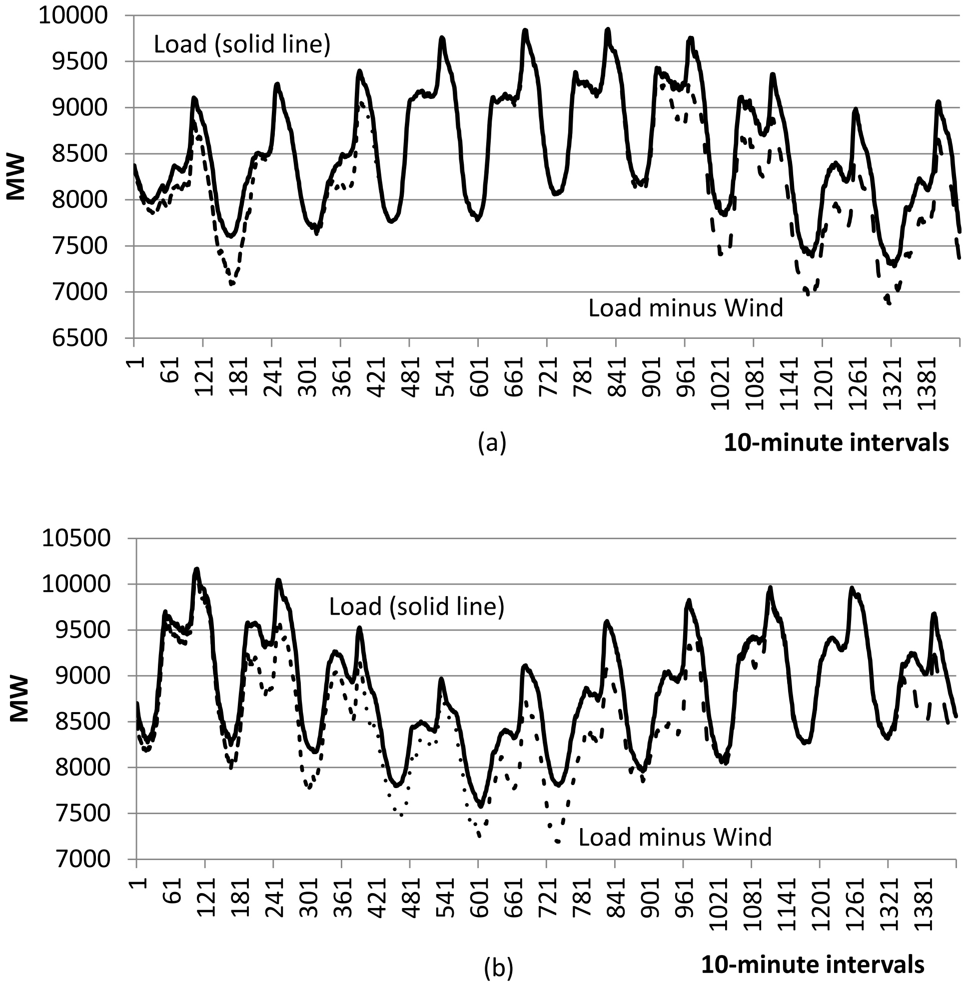

Figure 1: Alberta load and wind generation at 10-minute intervals, first (panel a) and last 10 days (panel b) in 2010

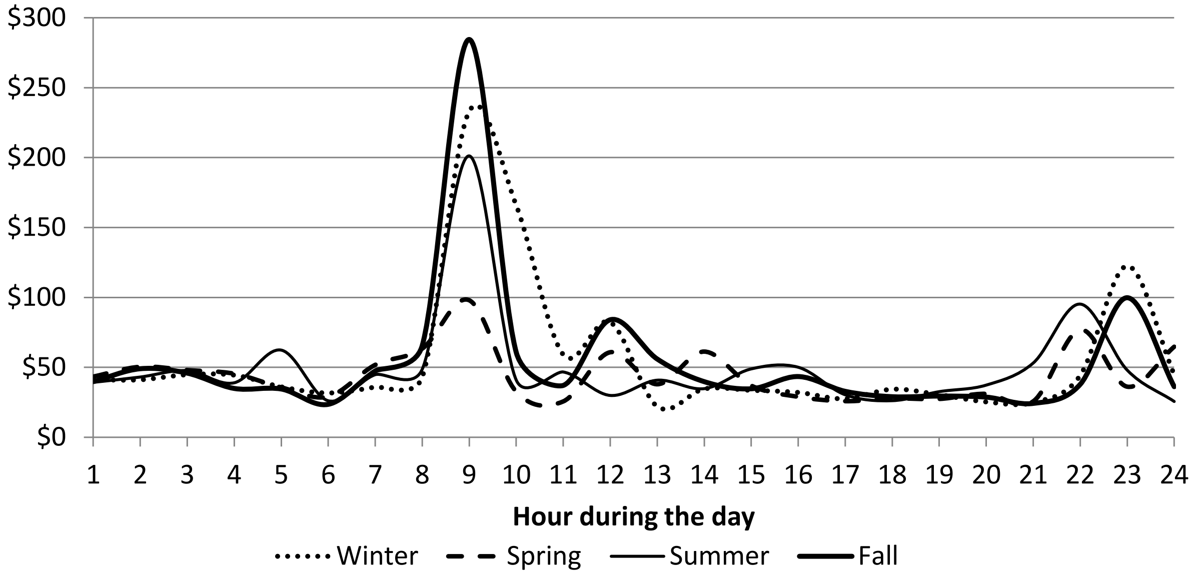

Figure 2: Average hourly Alberta prices ($/MWh), various seasons, 2010