Economics of co-firing coal and biomass: An application to Western Canada

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ABSTRACT

Co-firing biomass and coal in retrofitted power plants is an efficient means to reduce carbon dioxide emissions in the energy sector. Under IPCC reporting rules, the impacts of energy produced from biomass would not be reported in the energy sector, thereby effectively lowering the emission intensity of a power plant. In this study, a carbon tax is compared to a feed-in tariff for incentivizing conversion of coal plants to co-fire with biomass. In the application, a model of the Alberta electrical grid with an intertie to British Columbia is linked to a fiber transportation model for these provinces. Results indicate that there is an upper threshold on a carbon tax after which retrofitting of coal plants is less efficient than increasing natural gas generating capacity. This is not the case with a feed-in tariff as it specifically targets biomass energy. Although the optimal generating mix achieved with a carbon tax leads to lower aggregate emissions than the mix achieved using a feed-in tariff, it will result in higher average generating costs. Results indicate that it is optimal for Alberta to retrofit approximately 500 MW of current coal capacity (8.6%) to co-fire with biomass, although Alberta wood pellet production acts as a constraint on further conversions.

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1. Introduction

Many countries are hoping to transform their energy sectors away from coal power to renewable sources to reduce their carbon dioxide (CO_2) emissions. One option is to co-fire biomass with coal to reduce the CO_2 emissions intensity of coal plants. Co-firing biomass in existing coal-fired power plants is appealing due to the low incremental investment required to retrofit established facilities and because energy produced from biomass is considered to be carbon neutral (IPCC, 2006). Under IPCC reporting rules the impacts of energy produced from biomass would not be reported in the energy sector but in the Agriculture, Forestry and Other Land-Use (AFOLU) sector (previously the LULUCF sector). Carbon emissions from biomass energy are considered carbon neutral since the IPCC Guidelines assume that carbon lost during harvest equals carbon gained through regrowth. Consequently, many coal plants have been or are in the process of being retrofitted to co-fire with biomass (e.g., see IEA (2009)).

Whether biomass burning should be considered carbon neutral is debatable. As argued by Johnston and van Kooten (2014), biomass burning is only carbon neutral if there is no urgency in addressing climate change,

in which case the timing of CO_2 flux is unimportant. It only matters that over the harvest cycle the same amount of CO_2 is removed from the atmosphere by tree growth as was emitted producing electricity. If there is some urgency to address climate change, however, future removals of CO_2 from the atmosphere must be considered less important than current emissions, in which case biomass burning can no longer be considered carbon neutral.

The increased demand for biomass energy has resulted in the creation of new wood product markets, primarily in the form of wood pellets. Driven largely by EU policies, global wood pellet production has increased from 1.7 million tonnes (Mt) in 2000 to 15.7 Mt in 2010 (Lamers et al., 2012), primarily for use in the European market.[1]

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[1] European countries have agreed on a binding target to achieve a 20% share of renewable energy in total energy consumption by 2020. Co-firing biomass with coal is becoming more common in EU countries, with the Netherlands, the UK and Belgium leading the way. These countries have implemented various incentives for retrofitting coal plants. In the Netherlands, power producers receive a feed-in tariff of €67/MWh under the 2002 MEP (Milieukwaliteit van de Elektriciteits Productie). In the UK, electricity generators are required to obtain 12% of their energy from renewable sources, including biomass. It uses Renewable Obligation Certificates (ROC) to incentivize retrofitting of coal plants to co-fire biomass; the average price of an ROC was €55.9/MWh in 2012. Similarly, Belgium relies on Green Certificates (average price in 2012 was €118/MWh) to encourage large-scale retrofitting of coal plants.

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Although Europe is also a large producer, there is limited capacity to increase European pellet production. As a result, the wood pellet manufacturing sector in Canada has emerged as a significant supplier, exporting 1.9 Mt representing 90% of its pellet production to Europe in 2011.[2] As of 2012, British Columbia (BC) had 1,875,000 tonnes of wood pellet manufacturing capacity, accounting for 65% of Canadian capacity and production (WPAC, 2012). This sector has traditionally utilized low-cost mill residuals as feedstock, although significant increases in production will require incorporation of more costly fiber from forest operations. As a result of these European incentives, BC exported 840,000 tonnes of wood pellets to the UK and 240,000 to the Netherlands in 2012 (Industry Canada, 2013).

There are numerous risks to expanding or even maintaining exports of pellets from BC to Europe, including potential changes in European energy policies, the rapid rise of exports from lower-cost competitors and relatively high shipping costs. It is logical therefore to examine potential new markets as a hedge against too large an exposure to the European market, especially considering the high degree of policy risk associated with pellet exports to Europe. A logical market may be developing close to home.

Under the Copenhagen Accord, Canada agreed to reduce its greenhouse gas emissions by 17% from 2005 levels by 2020. Currently, coal-fired electricity generation in Canada is responsible for 77% of the CO_2 emissions from the electricity sector, despite generating only 15% of total production. With this in mind, the Government of Canada (2011), through an amendment to the Canadian Environmental Protection Act (1999), imposed an emission intensity standard for generating electricity from thermal power plants, although it would initially apply only to new plants and those refurbished because of their age. The standard was set at an emission intensity level commensurate with that for high-efficiency combined-cycle gas turbines (CCGT), initially determined to be 375 tCO_2/GWh but later raised to 420 tCO_2/GWh.

The new standard is likely to have its biggest impact on Alberta since Ontario had already mandated the elimination of coal-fired power in 2007, using financial incentives for biomass energy as an additional policy tool.[3] The Alberta electricity sector will play an important role if Canada is to comply with the Copenhagen Accord, as it has 5795 MW of installed coal-fired capacity, which represents 53% of its current electricity output. In 2007, Alberta became the first jurisdiction in North America to put a price on carbon; it introduced what amounted to (but was not called) a carbon tax that targeted large industrial emitters. Large emitters are required to reduce their carbon emission intensity by 12% or pay a $15-per-tonne tax on CO_2 emissions. A recent government proposal could see the tax increase to $40/tCO_2$ in hopes of mitigating emissions by 28%.[4] It is estimated that companies currently pay $1.80/tCO_2$ and that this would rise to $16/tCO_2$ if the tax was increased (Kleiss, 2013).[5]

While Alberta and British Columbia (which has no coal plants) have carbon taxes (albeit of different forms), the EU and Ontario rely on feed-in tariffs (FITs) that are implemented as a premium paid to energy produced from biomass (although the EU also employs carbon trading). Unlike a carbon tax, which penalizes emission-intensive technologies across the board, a FIT is designed to encourage investment in renewable energy technologies. As a result, it is expected that reliance on a carbon tax as opposed to a FIT will result in a much different generating mix.

In this paper, we examine optimal investment in generating assets in response to market incentives to reduce CO_2 emissions. We use the Alberta energy sector as our case study because of its significant reliance on fossil fuels, especially coal but also natural gas. Additionally, Alberta's proximity to BC allows it to have access to a significant amount of wood pellet manufacturing capacity for co-firing biomass and coal. Indeed, this may provide an opportunity for BC to expand its market while reducing its exposure to the risk of changes in foreign energy policies. In response to an increasing demand for climate change mitigation while providing reasonably priced electricity, co-firing may be beneficial for both provinces. The objectives of the current research are therefore (1) to examine the impact of different market incentives for encouraging the co-firing of biomass with coal; (2) to investigate the potential of reducing CO_2 emissions through co-firing biomass with coal; and (3) to determine the feasibility of marketing BC wood pellets in Alberta.

2. Carbon tax versus feed-in tariff

In this section, we examine how carbon taxes and feed-in tariffs differentially affect the generating mix. Consider Fig. 1 where the 2012 hourly Alberta load is depicted in panel (a). By sorting the hourly load in descending order, we derive the 2012 load-duration curve as shown in panel (b). The minimum load is referred to as the base load and is generally met with base-load power plants that rarely need to vary output. Nuclear, coal and CCGT assets constitute the main types of base-load plants.
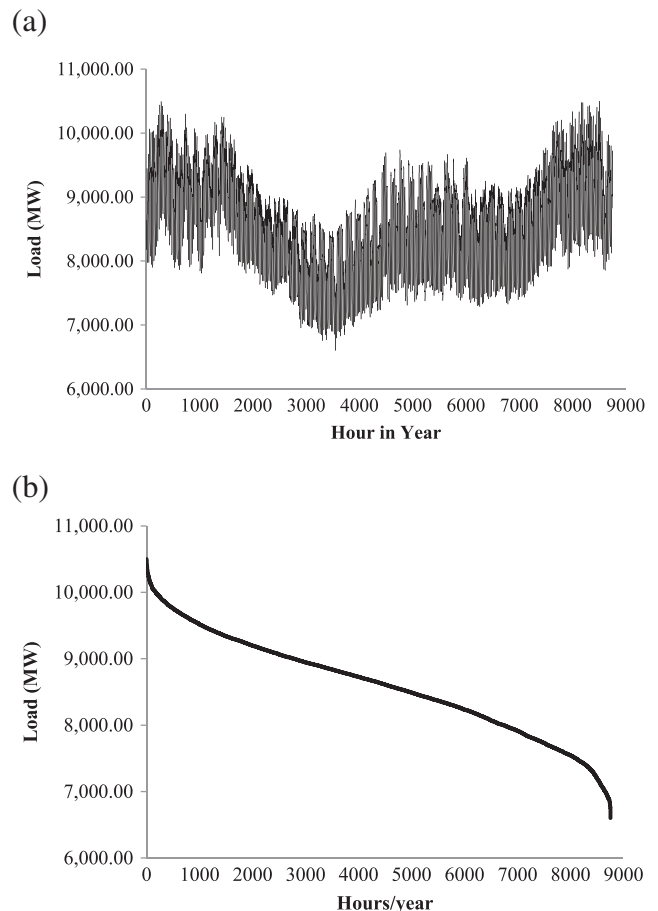
(a)

(b)

Fig. 1. 2012 Alberta load (panel a) and load duration curve (panel b).

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[2] http://www.pellet.org/production/production (accessed July 10th, 2013).

[3] Ontario's The Green Energy and Green Economy Act (2009) subsequently introduced feed-in tariffs for electricity generated from renewable sources, including a subsidy on biomass electricity of 13.0–13.8 ¢/kWh, which was increased to 15.6 ¢/kWh effective August 26, 2013. Two coal-fired power plants are currently undergoing a retrofit to burn biomass, including Nanticoke Generating Station which had been the largest coal plant and one of the largest single sources of emissions in North America. Ontario's capacity to convert biomass residuals to wood pellets is also increasing, with three wood pellet plants under construction and seven more proposed as of 2013 (Canadian Biomass, 2013).

[4] Alberta Environment Minister Diana McQueen has proposed a '40/40 plan' to come into effect by 2020; it raises the emission reduction target to 40% and increase the carbon price to C$40 per tonne.

[5] Unless otherwise indicated, all monetary units are in Canadian currency.

One can determine the generating mix for a particular grid using the load duration curve and screening curves, which provide the average capacity costs of a specific generating technology. A screening curve plots the annual revenue requirement (variable plus annualized fixed cost component) to retain a generator as a function of the generator's capacity factor, defined as the ratio of a power plant's actual output over a year to its potential output (capacity multiplied by 8760 h in a year). Screening curves are used to compare generation costs among generating assets by taking into account fixed cost, variable cost and load duration (Stoft, 2002, pp.34–36). Graphically, time (in hours) is plotted along the horizontal axis and cost along the vertical axis. Total cost comprised the initial capital expense, which constitutes the vertical intercept of a screening curve, and the variable costs, which represent the slope. The capital expense of installing capacity is the total amortized cost (including interest), while the operating expense constitutes fuel costs (converted from $/MWh to $/kWh) and annual operating and maintenance costs. Screening curves are assumed to be linear for simplicity – the variable cost is thus assumed to be constant as the capacity factor increases.

In Fig. 2, the load duration curve is given in the bottom right part of the diagram with screening curves representing four different technologies provided in the top right diagram. The technologies consist of a typical base-load coal plant, a CCGT base- to mid-load plant, an open-cycle gas turbine peak-load plant, and a base-load plant capable of co-firing a fuel mix consisting of 15% wood pellets and 85% coal. By dropping vertical lines from the points where two screening curves intersect down to the load duration curve, and then drawing the lines horizontally from the load duration curve to the vertical axis, one can determine the capacities of the associated technologies that should be built. This is shown in the diagram on the left in Fig. 2. Of course, the slopes and intercepts of the screening curves, and the load duration curve, are not fixed but fluctuate to a greater or lesser degree; the screening curves depend on the cost components discussed above (including importantly fuel costs), while the load duration curve will depend on weather and many other factors that affect demand for electricity from one year to the next. Further, access to reliable fuel sources, such as nearby coal deposits, varies from one region to another, which leads to varying generation mixes across jurisdictions. Nonetheless, this method of selecting a mix of generating assets provides some rough guidance for investors.

In Fig. 2, the base-load coal plant has high capital costs but low operating expenses per hour. To offset the high capital cost, the coal plant must have low operating expenses, so it is necessary to ensure that it operates near capacity – it must maintain a high capacity factor. The peak-load plant has a low capital cost combined with a high operating expense, making a low capacity factor optimal for this asset. The mid-load plant, on the other hand, operates at a capacity factor between that of a base-load coal plant and peaking facility. Finally, based on the screening curves in Fig. 2, it is not optimal to co-fire biomass with coal as the operating expense is currently not low enough to offset the initial capital cost at any capacity factor.

Without government policy, co-firing biomass and coal may not be considered as part of an optimal generating mix. However, two policies can be implemented for encouraging the co-firing of biomass and coal for energy production, namely, a tax on carbon and a feed-in tariff on electricity produced from biomass. We compare these two policy instruments.

The impact of a carbon tax or FIT on the generating mix can be analyzed using load-duration and screening curves. Fig. 3 depicts the situation where a carbon tax ($/tCO$_2$) penalizes high emission-intensive technologies. Although the capital expenditure required for each technology is unchanged, the tax will affect the operating costs of fossil fuel technologies, causing the slopes of their screening curves to become steeper. The greater are a technology's CO$_2$ emissions per unit of output, the greater is the increase in operating expenses. A summary of the CO$_2$-emission intensities of various technologies is provided in Table 2.

All generating assets depicted in Fig. 3 experience an increase in hourly operating expense as a result of a tax on carbon emissions, but coal in Alberta has an emission intensity of 936 kg CO$_2$ per MWh, which is higher than that of other fossil-fuel technologies (see Table 2). Thus, the slope of coal's screening curve is impacted the most. The CCGT power plant has the lowest emission intensity (420 kg CO$_2$ per MWh), so the slope of its screening curve is affected to a lesser extent. Peak-load gas plants have emission intensities somewhere between coal and CCGT, while the emission intensity of co-firing depends on the proportion of biomass included in the fuel mix and the assumption that biomass burning emits zero CO$_2$. Co-firing biomass with coal at a 15% rate will result in an operating expense (slope of the screening curve) that is not as steep as coal, possibly allowing co-firing to become cost effective at high capacity factors.
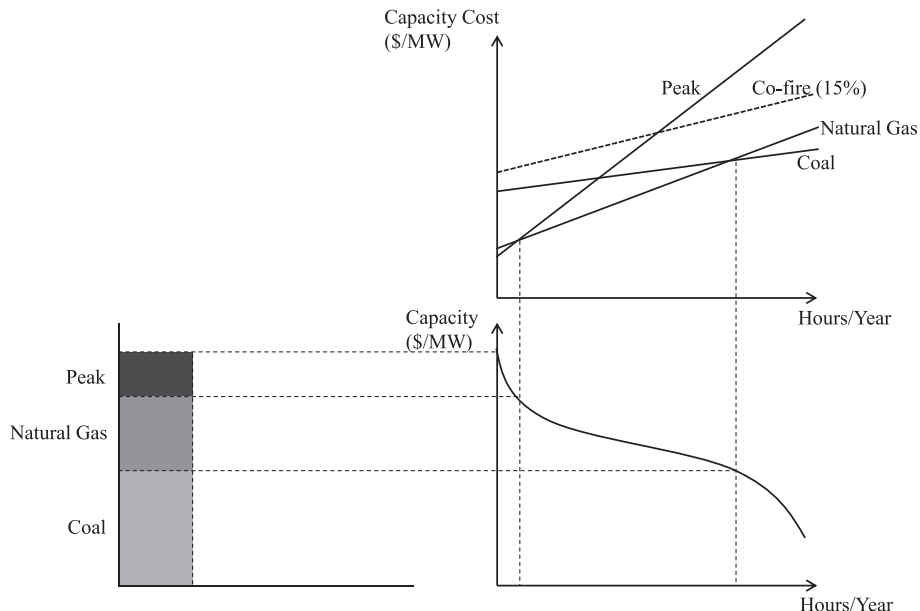

Fig. 2. Optimally installed generation capacities based on screening curves and load duration curve: Absent government policy.
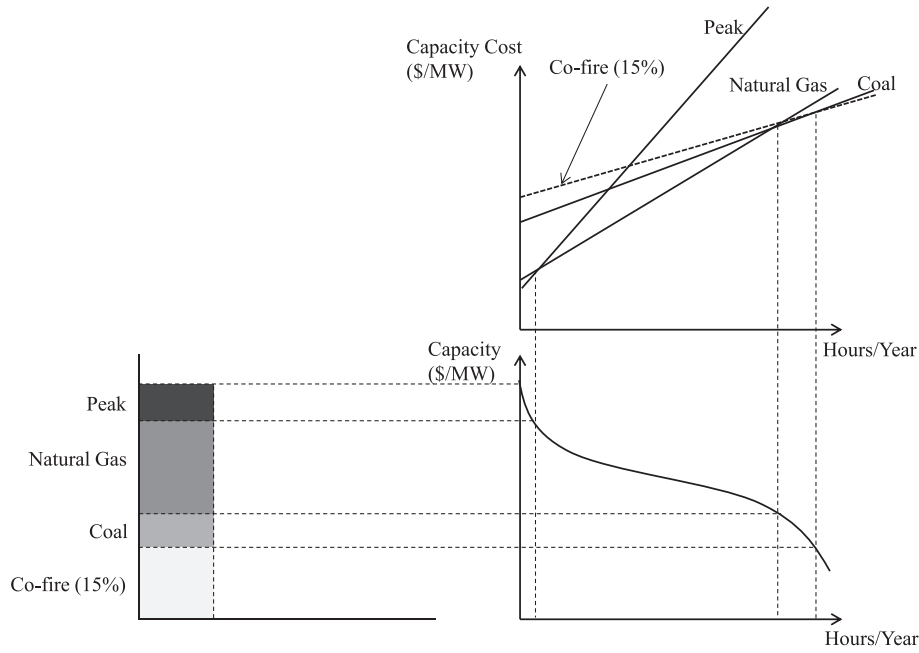
Fig. 3. Optimally installed generation capacities based on screening curves and load duration curve: Carbon tax scenario that increases the slopes of screening curves for fossil fuel generators but that of co-firing plants to a lesser extent.

As indicated in Fig. 3, with a carbon tax it is optimal to retrofit coal plants to co-fire with biomass. The intercept on the vertical axis representing the fixed cost is unchanged from Fig. 2, but the carbon tax reduces the effective slope – the variable cost – of operating a plant that co-fires biomass with coal because of the reduced emission intensity of such a plant relative to a coal-only power plant. That is, co-firing biomass at 15% is able to offset the high initial capital expense with relatively lower hourly operating costs (compared to coal alone), making it attractive to include some co-firing capacity in the generating mix. Further, relative to the mix in Fig. 2, the carbon tax reduces peak-load gas capacity due to its relatively high emission intensity, but increases base- and mid-load CCGT capacity at the expense of reduced coal capacity because gas emits less CO_2 per MWh than coal. Finally, while a carbon tax can be used to encourage investments in co-firing, it is unclear from Figs. 2 and 3 whether a carbon tax will be sufficiently high enough to even bring about significant co-firing capacity.

In contrast to a carbon tax, a FIT specifically targets investment in renewable energy technologies such as biomass power production. By subsidizing electricity generated on a per-kWh basis, a feed-in tariff lowers the variable operating expense – pivots the screening curve downwards as the slope flattens, in the same way that the carbon tax flattens the screening curve. Unlike a carbon tax, however, the FIT targets only renewable generating capacity, but often in a way that favors one renewable over another while leaving the screening curves of fossil fuel generators unchanged. With a feed-in tariff, one expects coal capacity to be driven out in favor of co-firing, while peak-load and CCGT gas plant capacities are unaffected. The optimal amount of co-firing capacity to install is expected to rise with increases in the FIT for biomass.

To examine the impacts of an emission intensity mandate and carbon taxes versus feed-in tariffs we consider the Alberta electricity grid. The objective of the Alberta Electric System Operator is continuously to balance the province's demand for electricity (or load) and power production at the lowest possible cost. The foregoing analysis used screening curves to indicate how decision makers might choose the mix of generating capacities under various incentives, including carbon taxes and feed-in tariffs. Other considerations such as the rates at which generating assets can change output (ramping rates), access to electricity from other jurisdictions via transmission interties, and various technical and engineering constraints also come into play. To model the choice of generating mix and take account of these factors, as well as supply of wood pellets, we employ a numerical mathematical programming model that is described in the next section.

3. Alberta electrical grid model

We extend a mathematical programming model of the Alberta electricity grid developed by van Kooten et al. (2012) by integrating a transportation model of wood pellets produced at various locations in British Columbia and Alberta. Each individual coal-fired generating unit in Alberta is modeled, with the decision maker able to retrofit each generator to burn biomass if optimal. The model is first used to examine solely the impact of the emission-intensity mandate, and then to compare the effects of different levels of a carbon tax versus different levels of a feed-in tariff, on the optimal generating mix and CO_2 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. Although private firms make decisions on the basis of prices, the model we develop assumes that the AESO decides on the decommissioning of extant fossil-fuel generation assets, investment in new natural gas assets, and retrofitting of current coal-fired generating capacity to co-fire biomass and coal. Some trade in electricity between Alberta and British Columbia is also permitted, although it is constrained by intertie transmission constraints and dictated on an hourly basis by price differentials between the provinces.

The AESO is thus assumed to maximize annual profit Π ($) subject to load, trade and engineering constraints. The profit function can be written as:

$$\Pi = \sum_{t=1}^{T} \left[P_{A,t} L_t - \sum_i (OM_i + b_i + \tau \varphi_i) Q_{i,t} + F \sum_i \gamma_i Q_{i,t} \right]$$
$$+ \sum_{t=1}^{T} \left[\left(P_{A,t} - P_{BC,t} - \delta \right) M_t - \left(P_{BC,t} - P_{A,t} - \delta \right) X_t \right] \qquad (1)$$
$$- \sum_r \sum_i \left(\alpha D_{r,i} + P_{w,r} \right) W_{r,i} - \sum_i (a_i - d_i) \Delta C_i,$$

where $i \in I = \{$CCGT, peak gas, coal, retrofitted coal$\}$ refers to the generation source and T is the number of hours in a year (8760).[6] The first term in Eq. (1) is the revenue associated with power generation where L_t refers to the demand or load that has to be met in hour t (MW); $P_{A,t}$ is the Alberta electricity price in hour t ($/MWh); $Q_{i,t}$ is the electricity produced by generator i in hour t (MW); OM_i refers to the hourly operating and maintenance cost of generator i ($/MWh); and b_i refers to the variable fuel cost of producing electricity using generator i ($/MWh), which is assumed to be constant for all levels of output.

We assume constant fuel prices because we lack data on how fuel prices change with output, plus the fact that much coal and natural gas is sold under long-term contracts, which implies that prices are fixed for long periods. Further, the price of fuel to a co-firing facility is implicitly assumed to be a weighted price of the coal and biomass costs. As to the market incentives for reducing CO_2 emissions, τ represents the carbon tax ($ per tCO_2) and φ_i is the emission intensity (kg CO_2 emitted per MWh) of generation source i's fuel source, where the emission intensity for a co-firing facility is adjusted to account for zero-emission biomass.

Lastly, F refers to the feed-in tariff ($/MWh) for biomass, which is adjusted by the proportion γ_i of the electricity produced from biomass in coal-fired generator i that has been converted to co-fire with biomass (with $F = 0$ for generators that do not burn biomass).

The second term in Eq. (1) represents the costs or revenues associated with the trade of electricity along the Alberta–BC transmission intertie. We let $P_{k,t}$ be the price ($/MWh) of electricity in province k ($=\{$AB, BC$\}$) in hour t; however, while Alberta prices vary hourly, the BC price is assumed to be fixed because all information on BC prices is proprietary. M_t refers to the amount of power imported by Alberta from BC at t, while X_t is the amount exported from Alberta to BC; δ is the transmission cost ($/MWh), which includes the costs of line losses.

Wood pellet costs are represented by the third term in Eq. (1). $W_{r,i}$ refers to the annual tonnes of wood pellets purchased from pellet producer r (discussed below) destined for co-firing at retrofitted coal generator i. $D_{r,i}$ is the distance (km) from pellet producer r to pellet consuming source i, multiplied by α which represents the cost of transporting one tonne of wood pellets a distance of one kilometer. $P_{w,r}$ represents the FOB pellet price ($/tonne) from pellet mill r. Specific information on wood pellet prices is presented in Section 4.

Finally, the last term in Eq. (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. In the case where generators are retrofitted from burning solely coal to burning a mix of coal and biomass, $(a_i - d_i)$ represents the annualized retrofitting cost and ΔC_i the amount of coal capacity that is retrofitted.

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

Demand is met in every hour :   (2)

$$\sum_i Q_{t,i} + \left(M_{BC,t} - X_{BC,t}\right) \ge D_t, \forall t = 1, ..., T$$

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

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

Generator capacity constraints : $Q_{i,t} \le C_i, \forall t, i$ (5)

Import transmission constraint : $M_t \le TR, \forall t = 1, ..., T$ (6)

Export transmission constraint : $X_t \le TR, \forall t = 1, ..., T$ (7)

Non-negativity : $W_{r,i}, Q_{i,t}, M_t, X_t \ge 0, \forall r, i, t$ (8)

R_i is the amount of time it takes to ramp production from plant i, while the capacity of the transmission intertie between the provinces is denoted by TR.[7]

The amount of wood pellets (tonnes) required in a given hour $\eta_{i,t}$ to supply a retrofitted coal-biomass power plant must equal the amount of electricity generated (MWh) for a given rate of co-fire divided by the heat content of wood pellets, $\lambda \approx 5$ MWh/t (EIA, 2012):

$$\eta_{i,t} = \frac{\gamma_i \times Q_{i,t}}{\lambda}, \forall t, i.$$ (9)

In addition, the pellets delivered to a retrofitted power plant from all sources r during the period under consideration (annually in our model) must be at least that required to produce the called for power:

$$\sum_r W_{r,i} \ge \sum_t \eta_{i,t} \quad \forall i.$$ (10)

Further, the amount of wood pellets shipped from pellet producing facility r must not exceed the capacity C_r^W (tonnes) of the plant:

$$\sum_i W_{r,i} \le C_r^W \quad \forall r.$$ (11)

It is assumed that all generators of a given type operate efficiently, with only the output of the marginal generator 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 start-up of thermal power plants associated with wind variability are not taken into account. The decision variables in the model are $Q_{i,t}$, ΔC_i (which includes the decision to retrofit a coal generator to co-fire with biomass), M_t, X_t, $\eta_{i,t}$, and $W_{r,i}$, with the latter two pertaining to wood pellets.

4. Data

In 2012, the Alberta generation mix consisted of 5795 MW of coal-fired generating capacity, 4164 MW of CCGT capacity, 1500 MW of peak-load natural gas capacity, 900 MW of hydroelectric generation, 409 MW of biomass capacity, and 1123 MW of installed wind generating capacity associated with 490 wind turbines. In addition, Alberta can trade power with British Columbia. The capacity of the existing intertie between Alberta and BC varies with direction, but we simply assume a single transmission capacity constraint of 750 MW. BC is dominated by hydroelectricity that accounts for 11,000 MW or 92.4% of BC's generating capacity and its hydro reservoirs have the capacity to store energy from Alberta.

Coal generating capacity is distributed across 16 coal-fired units in six power plants (Table 1), with an average emission intensity equal to 936 tCO_2/GWh (Table 2). Coal-fired generating stations in Alberta are optimally located near coal mines, as well as transmission lines connected to load centers. Coal plants within the province differ considerably with respect to location, age, efficiency and capacity. For example, the oldest coal unit in Alberta is Battle River 3, which was completed in 1969 and has an emission intensity of 931 tCO_2/GWh; Keephills 3, on the other hand, came on-line in 2011 and it has an emission intensity of 676 tCO_2/GWh (Table 1). While a power plant's age certainly has an impact on its emission intensity, so does the quality

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Table 1
Installed coal-fired capacity in Alberta, 2012.

Station unit	Capacity (MW)	Completed (year)	CO_2 (t/GWh)[a]	NOx (t/GWh)[a]	SO_2 (t/GWh)[a]
Battle River					
3	150	1969	931	1.9	5.5
4	150	1975	882	1.8	5.4
5	389	1981	1176	2.4	5.0
Genesee					
1	410	1989	980	2.0	2.0
2	410	1994	980	2.0	2.0
3	495	2005	676	0.7	0.9
HR Milner					
1	158	1972	1103	2.3	3.0
Keephills					
1	396	1983	1103	2.3	2.1
2	396	1983	1127	2.3	2.1
3	495	2011	676	0.7	0.6
Sheerness					
1	390	1986	1127	2.3	6.4
2	390	1990	1127	2.3	6.4
Sundance					
3	408	1976	980	2.0	1.8
4	386	1977	931	1.9	1.8
5	386	1978	833	1.7	2.0
6	386	1980	784	1.6	2.0

[a] Source: Environment Canada (2013).

of coal available as a fuel, the plant's utilization (i.e., its capacity factor), etc. Thus, the optimal installed capacity depends not only on fuel costs, but also on emission efficiency. Further, when an existing coal plant is retrofitted, the extant age of the plant will affect the expected life of a retrofitted facility and thereby the period over which the retrofit costs can be amortized. Finally, the location of a coal plant relative to a wood pellet producer will be a significant determinant of whether a coal plant chooses to retrofit. Increased hauling costs result in increased average generating costs through increased delivered wood pellet costs.

Alberta's load is characterized by significant weekly and seasonal variation. The average annual load in 2012 was 8203 MW with a maximum of 10,610 MW and a minimum of 6829 MW. Electricity prices for Alberta and BC are used to determine movements along the interties. In 2012, market clearing electricity prices averaged $90/MWh in Alberta, ranging from a low of $0 to a high of $1000. 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 contacts with independent power producers and BC Hydro's expected future costs.

4.1. Technical details

It is estimated that 234 coal-fired power plants have been retrofitted globally to co-fire with biomass on a commercial basis, with a majority co-firing at rates below 15% (IEA, 2009). In most cases, plants retrofitted to co-fire on a continual basis do so at rates varying from 5% to 15% (IEA, 2012). Indeed, co-firing proportions in conventional coal plants have

increased from roughly 1% to 10% of energy input to over 20% in the past decade (IEA, 2009). Recent studies suggest that substitution of coal for biomass can readily be achieved for levels up to 50%, depending on the co-firing technique (DENA, 2011; IRENA, 2012; Vattenfall, 2011). Direct co-firing with pre-milled wood pellets in pulverized coal-fired boilers allows for greater flexibility in co-fire rates. However, co-firing at high rates may lead to efficiency losses due to fouling and slagging associated with corrosion (IEA, 2009; IRENA, 2012). This could significantly increase operating costs.

As a result, this study examines a range of co-firing rates. In this way, current coal-fired capacity within Alberta can be relied upon with only minor retrofit costs. Co-firing at these rates requires a capital investment for boiler modifications and fuel handling. Information on construction and operating costs, CO_2 emissions and ramping rates for generators are provided in Table 2. The overnight construction cost of 'retrofit' refers to the incremental investment required to transform an already existing direct feed coal-fired generating station to run on a combination of coal and biomass as a fuel source.

In the analysis, both available hydro- and wind-generated power are subtracted from load in each hour as they are considered 'must run'. Alberta's hydroelectricity primarily consists of run-of-river facilities, while, in the current model, the total number of wind turbines is held fixed. This is done so that we can focus solely on biomass energy while not being concerned about the potential interaction between feed-in subsidies for biomass versus wind.

4.2. Wood pellets

The wood pellet industry in western Canada is dominated by British Columbia, with minor productive capacity in Alberta. British Columbia is home to approximately 1.9 Mt of wood pellet manufacturing capacity, centered primarily in the central and northern regions of the BC Interior (Table 3). This industry has grown substantially in recent years, with two new manufacturing plants established in 2013 (Merritt and Kamloops). British Columbia is looking to take advantage of this expanding market with two new proposed plants in Northern BC, providing an additional capacity of over 200,000 tonnes per year (Canadian Biomass, 2013).

Wood pellet manufacturing in British Columbia is ideally located in close proximity to sawmill residue supply from lumber manufacturing, as well as increased fiber supply from un-merchantable timber from the mountain pine beetle infestation. Nevertheless, the fuel cost associated with wood pellets to generate power is sensitive to the distance between the power plant and pellet mill. Table 3 provides estimates of the transport costs from pellet producers to coal-fired power plant in Alberta ($/t). This calculation is based off estimated trucking costs of a Super B-train grain truck, which is an 8-axle configuration with two trailers, hauling 44 tonnes of wood pellets. On average, wood pellets from within BC have an estimated transportation cost of $51/t to an Albertan coal-fired power plant, while sourcing pellets from within Alberta has an average estimated transport cost of $32/t.

Table 2
Construction and operating costs ($2012), CO_2 emissions, and ramp rates of various generating assets.

Asset	Years to build	Construction costs[a]		Variable costs ($/MWh)[a]		Emissions intensity (tCO_2/MWh)	Ramp rate % of capacity per hour[c]
		Overnight ($/kW)	Decommission as % of overnight	O&M	Fuel		
Coal	4	2658.0	24.0	4.25	7.75	0.936[b]	2.5
Retrofit	1	274.0	24.0	n.a.	n.a.	n.a.	2.5
Wind	3	1300.0	n.a.	0.00	0.00	0.015	n.a.
Hydro	4	2134.0	n.a.	2.55	1.01	0.009	n.a.
CCGT	3	927.0	10.0	9.87	14.69	0.420	7.5
OCGT	2	634.0	10.0	14.70	19.56	0.600	12.5

[a] EIA, 2012.
[b] Average emission intensity of coal plants within Alberta as of 2012. Emission data from Environment Canada.
[c] Estimates based on AESO (2010, p.13) and total system ramp rate of 600 MW per hour.

Table 3
Estimated cost of transporting wood pellet from producer to power plant ($/tonne).

| Pellet producer | | Transportation cost to power plant | | | | | |
Province	Capacity	Battle River	Genesee	HR Milner	Keephills	Sheerness	Sundance
Location	(tonnes/year)*						
British Columbia		($/tonne)					
Merritt	90,000	57	51	43	49	53	48
Kelowna	50,000	52	47	48	48	47	48
Kamloops	35,000	52	46	38	44	48	43
Prince George	400,000	47	42	34	40	57	39
Armstrong	50,000	47	43	44	44	43	44
Burns Lake	400,000	66	55	47	53	70	52
Strathnaver	200,000	57	46	38	44	61	44
Quesnel	90,000	60	48	40	46	63	45
Williams Lake	150,000	63	52	44	50	64	49
Houston	150,000	71	60	52	57	75	57
Vanderhoof	140,000	59	48	40	45	63	44
Princeton	90,000	62	56	48	54	58	53
Vanderhoof	30,000	59	48	40	45	63	44
Alberta							
Grande Cache	25,000	35	24	10	22	43	21
La Crete	60,000	51	46	39	45	58	43
Slave Lake	60,000	25	17	29	16	32	16
Total capacity	2,020,000						

Estimates of $/tonne based on Super B-train grain truck, hauling a maximum of 44 tonnes.
* Biomass Wood Markets, 2013.

It is assumed that a retrofitted co-firing power plant in Alberta must pay at least as much as what a pellet manufacturer would receive by shipping overseas. Wood pellet prices are provided in Fig. 4; prices averaged $135.88/t (FOB from the Port of Vancouver) in 2012, reaching a high of $140.25/t and a low of $130/t. Since this price includes the shipping cost from the pellet producer in the BC interior to Vancouver, average shipping costs of $41.93/t during this period need to be subtracted, thereby providing an average FOB mill price of $93.95/t (Argus Biomass Markets, 2012). Thus, to obtain prices in Alberta, it is necessary to add the cost of transporting pellets from the BC mill to an Alberta power plant (Table 3). The average fuel cost of wood pellets for Albertan coal-fired power plants is approximately $27.18/MWh.

5. Model results

To understand how Alberta's generating mix might respond to policies that aim to achieve these emission-intensity targets, we employ a carbon tax that varies from $0 to $200 per tCO$_2$. This policy is compared to the use of a feed-in tariff that varies from $0 to $120 per MWh of biomass energy produced. A feed-in tariff is a more common market incentive to encourage the transition towards biomass energy generation. In essence, we wish to determine the regulatory regimes under which the energy sector in Alberta is able to compete with the EU for British Columbian wood pellets. As well, we examine the
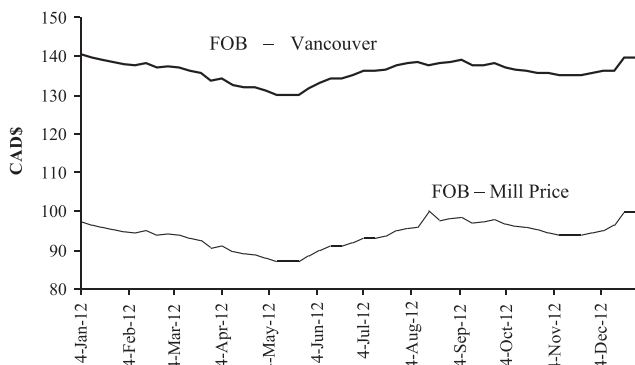
Fig. 4. Wood pellet prices (C$ per tonne), Weekly 2012. Source: Argus Biomass Markets.

different effects a tax and a subsidy have on the optimal generating grid in Alberta, with the ability to co-fire coal with biomass.

5.1. Capacity and generation

First, consider the impact of a carbon tax on the optimal generation mix in Alberta. In Table 4, the current generating mix is provided in the first row, while the optimal results under different policy scenarios are provided in the following rows. As indicated in Section 2, it appears as though there are lower and upper carbon tax thresholds in which co-firing may be optimal. Further, if the co-firing rate is too low, it will never be optimal to retrofit a coal plant.

In Table 4, the carbon tax drives a majority of the pure-fired coal out of the generating mix, for either a 5% or 15% co-fire rate. Under both co-firing rates, coal capacity declines from 5795 MW to 359 MW as the carbon tax increases from $0 to $200 per tCO$_2$. Regardless of the co-firing rate, as the carbon tax increases to $200/tCO$_2$, 3100 MW of new natural gas capacity is added because it is relatively cheaper to build and operate due to low fuel costs as well as relatively low emission intensity.

If we were to co-fire at a 5% rate of biomass as fuel, co-firing would never be the optimal choice under a carbon tax scenario. Due to the small amount of biomass as a percent of total fuel, the reduction in the effective emission intensity is insignificant. As a result, the benefit of co-firing (avoided carbon taxes) falls below the required retrofit cost, thus never allowing co-firing at 5% to become the optimal choice.

If we increase the co-fire rate to 15%, it becomes optimal to retrofit up to 3398 MW of currently installed coal capacity to co-fire with biomass. At a carbon tax of $50/tCO$_2$, the avoided carbon tax associated with co-firing at 15% outweighs the retrofit cost to convert a coal plant to use both biomass and coal. In fact, at this level, 800 MW of natural gas peak-load generation is also removed. In addition, average electricity generating costs are $5.71/MWh lower with the 15% co-fire scenario than they are for the 5% scenario, assuming a carbon tax of $50/tCO$_2$. These savings represent the low retrofit cost required to allow biomass and coal to be co-fired in current coal capacity, along with reduced applicable carbon taxes through lower emission intensities.

When the carbon tax becomes too high, low-emission natural gas pushes coal electrical generation out of the mix, with no biomass entering whatsoever. Under the 15% co-firing rate, this appears to happen at a carbon tax somewhere above $100/tCO$_2$. Although co-firing with

Table 4
Optimal generating capacities, various scenarios.

Scenario	Co-fire (MW)	Coal (MW)	CCGT[a] (MW)	OCGT[a] (MW)	Electricity cost ($/MWh)	Wood pellets (tonnes)
Initial	0	5795	4164	1500	21.70	0
5% Co-fire rate						
Carbon tax						
$0	0	5795	4164	1500	21.70	0
$50	0	5795	4164	739	59.07	0
$100	0	590	7165	1500	122.20	0
$150	0	929	7090	1500	139.68	0
$200	0	359	7265	1500	161.09	0
Feed-in tariff						
$0	0	5795	4164	1500	21.70	0
$30	0	5795	4164	1375	21.70	0
$60	0	5795	4164	1375	21.70	0
$90	5795	0	4164	1418	35.84	507,576
$120	5795	0	4164	1418	34.90	507,576
15% Co-fire rate						
Carbon tax						
$0	0	5795	4164	1500	21.70	0
$50	3398	1736	4164	699	53.36	890,185
$100	990	0	6417	1500	115.48	228,972
$150	0	929	7090	1500	139.68	0
$200	0	359	7265	1500	161.09	0
Feed-in tariff						
$0	0	5795	4164	1500	21.70	0
$30	95	5700	4164	1375	22.15	25,000
$60	5795	0	4164	1418	34.32	1,522,842
$90	5795	0	4164	1418	31.52	1,522,842
$120	5795	0	4164	1418	28.71	1,522,842

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

biomass allows coal capacity to lower their emission intensity, it is offset by the substantial carbon payments made at high carbon tax rates. At such rates, there are cost savings in transforming the electrical grid towards lower emitting natural gas.

If a feed-in tariff is used as a financial instrument to encourage currently installed coal capacity to co-fire with biomass, we see a much different picture. First, under both low and high rates of co-firing, a large enough feed-in tariff is successful at encouraging co-firing capacity to enter the optimal generating grid. As indicated in Table 4, a feed-in tariff of $60/MWh is not a sufficient financial incentive to retrofit coal plants to co-fire at 5%. Meanwhile, if we allow co-firing up to 15%, a similar feed-in tariff encourages 5795 MW of coal capacity to be retrofitted. Since the FIT is effectively a subsidy on energy produced from biomass, the greater the co-firing rate, the greater the subsidy received.

Since a carbon tax affects all fossil fuel generating assets, it results in a very high average generating cost ($/MWh) to meet the load requirements in Alberta. The most co-firing capacity added while using a carbon tax is under a tax of 50 $/tCO$_2$ while co-firing at a 15% rate. Under this rate, 3398 MW of coal capacity is retrofitted to co-fire with biomass, using 890,185 tonnes of wood pellets. The price on carbon will impact a significant amount of the generating sector within Alberta, resulting in an average price of electricity of $53.36/MWh. Meanwhile, co-firing at a similar 15% rate with a $60/MWh FIT for biomass results in a retrofit of all the currently installed coal capacity. Under this scenario, 1.5 Mt of wood pellets are required to fuel the 5795 MW of co-firing capacity, more than under any carbon tax scenario. At this point, the average generating cost to meet Alberta's load is only $34.42/MWh. Since a FIT only targets biomass specifically, it incentivizes a greater amount of co-firing capacity, at a much lower generating cost to Alberta.

5.2. Reducing carbon dioxide emissions

Although a feed-in tariff is more successful at encouraging biomass co-firing in currently installed coal capacity, it is unclear how successful

the policy is at reducing carbon dioxide emissions. The reason is that a FIT specifically targets biomass energy production but does not target CO$_2$ emissions per se. Table 5 provides emission and abatement costs found for optimal generating mixes in Alberta, under various regulatory regimes. Two trends are apparent from the emissions output provided in Table 5. First, a tax on carbon in the electricity generating sector leads to lower optimal CO$_2$ emissions than those found when relying on a feed-in tariff on biomass electricity production. The lowest level of CO$_2$ emissions under a carbon tax is a significant 20 Mt lower than that under a feed-in tariff. Indeed, there is virtually no realistic combination in which a FIT for biomass results in lower emissions from the Alberta electricity sector than relying on a carbon tax. FITs of $90 and $120 per MWh do little because co-firing capacity is constrained by current coal capacity; instead, it would be necessary to construct new biomass capacity, but such new capacity is much more expensive than relying on the conversion of current coal plants to co-fire with wood pellets. Even if this were not the case, current wood pellet manufacturing capacity will inevitably be maxed out.

The second trend, which can be identified from Table 5, is that a tax on carbon emissions is more cost effective than a feed-in tariff on biomass in reducing CO$_2$ emissions. Consider a co-fire rate of 15%, a carbon tax of $50 per tCO$_2$ results in 42.6 Mt of emissions – costing $253.06 per avoided tCO$_2$. Meanwhile, a feed-in tariff of $120/MWh reduced emissions to only 49.8 Mt of CO$_2$ – costing $355.37 per avoided CO$_2$. Since abatement costs increase with the feed-in tariff (and carbon tax for that matter), it is clear that any higher feed-in tariff will inevitably result in a higher abatement cost.

5.3. Impact of Canadian coal-fired performance standards

By 2015, when Canada's emission-intensity regulation for new and refurbished coal plants comes into effect, it is expected that seven of Alberta's 16 coal-fired generators will be affected by the new regulations within the first ten years. As identified in bold in Table 6, this constitutes 2024 MW (35%) of currently installed generating capacity. To examine how this policy will impact Alberta's optimal generating mix, as well as the potential for relying on co-firing as a compliance strategy, this scenario has been integrated in the numerical model outlined in Section 3. The current emission intensity of these units is 961 tCO$_2$/GWh, or more than double the 420 tCO$_2$/GWh standard, which implies that the seven units affected by the regulation will either have to co-fire at 56% or shut down entirely.

Although most co-firing is done at or below 15%, there are examples of fully converted pulverized coal plants relying on high rates of direct co-fired generation. Unit #4 of the 'Les Awirs' power plant in Belgium was fully retrofitted to burn biomass for upwards of 100% of its 80-MW capacity; this was followed, in 2011, with the retrofit of the 200-MW capacity unit #4 of the 'Rodenhuise' coal plant to burn only

Table 5
Total emissions and abatement costs under 5% and 15% co-fire scenarios.[a]

Scenario policy	5% Co-fire		15% Co-fire	
	Emissions (Mt CO$_2$)	Abatement cost($/tCO$_2$)	Emissions (Mt CO$_2$)	Abatement cost($/tCO$_2$)
Carbon tax				
$0	56.5	n.a.	56.5	n.a.
$50	45.6	262.18	42.6	253.06
$100	32.2	323.30	33.5	318.08
$150	29.9	348.41	29.9	348.41
$200	29.9	410.99	29.9	410.99
Feed-in tariff				
$0	56.5	n.a.	56.5	n.a.
$30	56.5	n.a.	56.4	240.33
$60	56.5	n.a.	49.8	287.48
$90	54.3	715.74	49.8	321.48
$120	54.3	749.39	49.8	355.37

[a] n.a. refers to not applicable or negligible.

Table 6
Age and capacity of coal-fired units in Alberta — Units affected by Canadian regulations within first 10 years of implementation (2015–2025) indicated in bold.

Station Unit	Established (year)	Capacity (MW)	Age in 2015	Useful years left by 2015
Battle River				
3	**1969**	**150**	**46**	**−1**
4	**1975**	**150**	**40**	**5**
5	1981	389	34	11
Genesee				
1	1989	410	26	19
2	1994	410	21	24
3	2005	495	10	35
HR Milner				
1	**1972**	**158**	**43**	**2**
Keephills				
1	1983	396	32	13
2	1983	396	32	13
3	2011	495	4	41
Sheerness				
1	1986	390	29	16
2	1990	390	25	20
Sundance				
3	**1976**	**408**	**39**	**6**
4	**1977**	**386**	**38**	**7**
5	**1978**	**386**	**37**	**8**
6	**1980**	**386**	**35**	**10**

biomass. In Denmark, the 250-MW unit #1 of the 'Amager' facility can now directly co-fire biomass with coal at ratios ranging from zero to 100% of boiler capacity. There are now two co-fired, direct feed power plants in Canada: The 4000-MW capacity 'Nanticoke' generating station in Ontario is a retrofitted pulverized coal plant that recently completed test runs with biomass generating up to 100% of the plant's capacity. Ontario's 230-MW capacity 'Atikokan' power plant recently completed tests using wood pellets to generate as much as 100% of the plant's power capacity. Atikokan retrofitted to co-fire high rates of biomass at a cost of $200 million, or $870/MW.

Despite this, there is little experience co-firing at high rates over a significant period of time. There are many uncertainties regarding high rates of co-firing including fouling and slagging associated with corrosion, as well as issues related to ensuring a long-term supply of biomass. In the current application, we assume that, at a 56% co-firing (to comply with the new regulations), the retrofit cost would be $870/MW. Further, annual biomass supply is assumed to be constrained by 2012 wood pellet manufacturing capacities of 1,875,000 and 145,000 tonnes in British Columbia and Alberta, respectively.

Model results are provided in Tables 7 and 8. In Table 7, the optimal generating mix in Alberta is dependent on whether or not the option to co-fire exists, as well as the regulatory environment in place. The 'initial' scenario highlights the current (2012) generating mix, while other scenarios represent situations where the Alberta generating mix must comply with the new performance standards for new and refurbished coal plants. That is, the scenarios force the seven generating units indicated in Table 6 to retrofit to co-fire to reduce their respective emission intensity to the performance standard or shut down.

The 'Current' policy scenario in Table 7 represents the case where coal plants in Alberta must meet the emission-intensity regulation, but no other policies (carbon tax or feed-in tariff) are implemented. It is then optimal for 495 MW of currently installed coal-fired generating capacity to co-fire with biomass. The remaining 1529 MW of coal capacity subject to the performance standard is shut down. Alberta will also require 484,998 tonnes of wood pellets manufactured from Alberta and British Columbia.

As indicated in Table 8, the 495 MW of installed co-fired capacity is spread across three generating units: 158 MW in H.R. Milner; 61 MW in Sundance 4; and 275 MW in Sundance 5. Although 85,000 tonnes of wood pellets are sourced from within Alberta to fuel these generating units, 400,000 tonnes per year are sourced from British Columbia. Due

to its proximity, Alberta requires all of the output from the current wood pellet producer in Prince George. As a result, 129,993 tonnes of wood pellets annually are shipped to H.R. Milner and 270,077 tonnes annually to Sundance 5. Meanwhile, the remainder of the annual wood pellet demand is sourced from within Alberta. H.R. Milner demands an additional 25,000 tonnes annually which is met by the Grand Cache pellet producer, while Sundance 4 exclusively sources its 60,000 annual tonnes of wood pellets from Slave Lake. The average delivered price of wood pellets is $123.95, which equates to roughly $24.79 per MWh.[8]

The 'Carbon tax' and 'Feed-in tariff' scenarios indicate how changes in the carbon tax and FIT affect the choice of optimal generating mixes. Unlike when there is no tax or FIT, all of the 2024 MW of coal capacity affected by the regulation is retrofitted to co-fire under whenever the carbon tax is $50/tCO$_2$ or higher, or the FIT is $30/MWh or higher. Unlike with a higher FIT, the remaining optimal coal capacity falls significantly as the carbon tax increases; optimal installed capacity falls from 3771 MW for a carbon tax of $50/tCO$_2$ to 357 MW for a tax of $200/tCO$_2$. In contrast, the optimal capacity of coal generation to retain remains at 3771 regardless of the level of the FIT. As a carbon tax punishes emissions regardless of the source, this policy again leads to significantly lower emissions than any feed-in tariff on biomass.

All scenarios with either a carbon tax, or feed-in tariff, require slightly less than 2.0 Mt of wood pellets, generating approximately 10 TWh of electricity from biomass. The optimal wood pellet shipments for a FIT of $30/MWh from biomass are provided in Table 8. Since any of the regulatory environments considered in Table 7 require a co-fire retrofit of all seven affected coal plants, the shipments in Table 8 are consistent with all scenarios. The wood pellet manufacturing sector in Alberta is fully utilized, while 98% of British Columbia's wood pellet manufacturing capacity is required to fuel plants in Alberta. As a result, 145,000 tonnes of wood pellets are derived from within Alberta, while 1,841,014 tonnes are sourced from British Columbia. In fact, Battle River Unit 4, and Sundance Units 3, 5, and 6, depend solely on British Columbian wood pellets.

Depending on hauling costs, delivered wood pellet prices vary from a low of $127.86/t for H.R. Milner to a high of $147.98/t for Sundance Unit 5. Based on optimally determined shipments, the hauling cost for H.R. Milner is $31.79/t, while the same cost for Sundance Unit 5 is $51.91/t. The average delivered wood pellet price is $141.05/t, or approximately $28.21 per MW, when taken across all seven co-firing units.

It is unclear whether a feed-in tariff will be the best choice for Alberta. On the one hand, average generating cost using a feed-in tariff of $30/MWh is $8.04 per MWh higher than if no additional policy was in place ($49.21 vs $41.17). However, due to the coal-fired regulations, the optimal generating grid in Alberta may result in lower total generating capacity if no additional policy is put in place. In the first ten years of the performance standard implementation, if no additional policy is used, it is optimal for 1529 MW of coal capacity to shut down, while only 495 MW of co-firing capacity is added. This scenario leads to the lowest level of installed generating capacity in Alberta, with the province relying heavily on imports of hydroelectricity from British Columbia over a 750 MW intertie. On the other hand, the use of a feed-in tariff results in an additional 1404 MW of generating capacity than if no further policy were in place. This allows for greater electrical independence from British Columbia, driven mainly through 2024 MW of retrofitted co-firing capacity.

6. Concluding discussion

In light of the external costs associated with CO$_2$ emissions, and the favorable treatment of CO$_2$ emissions associated with the use of biomass

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[8] This calculation is based off 1 tonne of wood pellets produces 4.8–5.2 MW of electricity.

Table 7
Optimal electrical generating assets for meeting coal-fired performance standards in Alberta.

Scenario *Policy*	Co-fire (MW)	Coal (MW)	CCGT (MW)	OCGT (MW)	Electricity Cost ($/MWh)	Emissions (Mt CO$_2$)	Abatement Cost ($/tCO$_2$)	Pellets (tonnes) ($/tCO$_2$)
Initial	0	5795	4164	1500	21.70	56.54	n.a.	n.a.
No co-fire	n.a.	3771	4164	1500	41.17	47.77	135.79	n.a.
Co-fire								
Current	495	3771	4164	1500	36.84	47.45	169.92	484,998
Carbon tax								
$50	2024	3771	4164	810	76.94	36.87	221.45	1,985,328
$100	2024	599	3196	1500	108.88	30.66	265.50	1,985,328
$150	2024	934	3263	1500	126.75	28.44	295.01	1,984,637
$200	2024	357	3087	1500	147.18	28.34	351.51	1,984,107
Feed-in-tariff								
$30	2024	3771	4164	1375	49.21	47.61	250.90	1,985,616
$60	2024	3771	4164	1375	52.86	47.61	284.25	1,985,622
$90	2024	3771	4164	1375	56.39	47.61	316.38	1,986,007
$120	2024	3771	4164	1375	60.04	47.61	349.73	1,986,007

energy, electrical grids in many jurisdictions are increasingly burning wood pellets with coal in retrofitted power plants to reduce their CO$_2$ emissions. What makes this feature appealing is the low incremental investment required to transform a coal-dominated grid into one that utilizes a combination of coal and biomass. In addition to the low costs of retrofitting coal plants, financial incentives, especially carbon taxes and feed-in tariffs for biomass, have been used to facilitate the transition towards this lower emitting fuel combination. However, a carbon tax will generally lead to a generating mix that relies more on low-emission natural gas, which the overarching renewable energy policy seeks to avoid.

Feed-in tariffs were perhaps the most popular financial incentive adopted by EU member states in the electricity sector in response to the EU's target of reducing emissions by 20% from 1990 levels and obtaining 20% of energy from renewable sources by 2020. In October, 2014 the EU adopted even more aggressive targets to be implemented by 2030: CO$_2$ emissions are to be reduced by 40% from 1990 levels, targets are to be legally binding on all member states (whereas the 2020 targets had varied among states), the share of renewables in the EU's energy mix is to rise to 27%, and energy efficiency improvements of 27% are to be realized. The burden of the costs is to be shared by taxpayers and, in the case of electricity, by ratepayers, and costs could be potentially quite high. This is no more evident than in Germany, which currently leads the EU in installed biomass capacity (7.11 GW) but with electricity prices 48% higher than the EU average. Compared to a carbon tax, a feed-in tariff may lead to higher costs of abating CO$_2$, although the majority of EU countries continue to rely on feed-in tariffs or other subsidies to incentivize greater use of bioenergy (as well as solar and wind). The overall impact of these policies remains, for the most part, unknown.

In addition to policies regarding the incentivizing of biomass burning in thermal power plants, commercial co-firing has many challenges. A large barrier is securing a reliable supply of biomass at sufficiently low cost. As transportation costs are a significant driver of the economics behind co-firing, proximity to fiber is a potential barrier. With this in mind, the Alberta–BC case study was used to identify the feasibility of co-firing wood pellets in existing coal plants, as well as the impacts of using a carbon tax or a feed-in tariff to incentivize retrofitting of coal plants. These provinces were used in the case study because Alberta's grid is dominated by coal-fired, base-load power plants, while British Columbia has a significant amount of wood pellet manufacturing capacity. Thus, co-firing wood pellets with coal may be a cost effective

Table 8
Optimal wood pellet shipments to supply Alberta co-fired generators subject to performance standards and feed-in tariff of $50/MWh.

Pellet producer		Shipments to coal-fired power plant						
Prov. *Location*	Capacity (tonnes/year)[a]	Battle River		HR Milner	Sundance			
		Unit 3	Unit 4	Unit 1	Unit 3	Unit 4	Unit 5	Unit 6
British Columbia					(tonnes)			
Merritt	90,000	0	0	0	0	0	0	90,000
Kelowna	50,000	37,185	12,815	0	0	0	0	0
Kamloops	35,000	0	0	0	13,468	21,532	0	0
Prince George	400,000	0	134,370	0	265,630	0	0	0
Armstrong	50,000	50,000	0	0	0	0	0	0
Burns Lake	400,000	0	0	0	0	21,244	378,756	0
Strathnaver	200,000	0	0	130,035	0	69,965	0	0
Quesnel	90,000	0	0	0	0	0	0	90,000
Williams Lake	150,000	0	0	0	91,244	0	0	58,756
Houston	150,000	0	0	0	0	116,014	0	0
Vanderhoof	140,000	0	0	0	0	0	0	140,000
Princeton	90,000	0	0	0	0	90,000	0	0
Vanderhoof	30,000	0	0	0	30,000	0	0	0
Alberta								
Grande Cache	25,000	0	0	25,000	0	0	0	0
La Crete	60,000	60,000	0	0	0	0	0	0
Slave Lake	60,000	0	0	0	0	60,000	0	0
Total capacity	2,020,000	147,185	147,185	155,035	400,343	378,756	378,756	378,756

Estimates of $/tonne based on Super B-train grain truck, hauling a maximum of 44 tonnes.
[a] Biomass Wood Markets, 2013.

strategy for complying with new emission-intensity regulations of 420 tCO$_2$/GWh. Independent of any other policies, our results indicate that it would be optimal to retrofit approximately 500 MW (or 8.6%) of Alberta's extant coal capacity to co-fire with biomass, although conversion of more generating capacity might be limited by the availability of wood pellets originating in Alberta.

As noted, there has been a significant increase in wood pellet production capacity in recent years due in a large part to aggressive EU CO$_2$-emission reduction policies. In the last decade, Canada has benefitted from this growing trend by increasing exports overseas, adding value to its forest product sector. With the potential development of domestic demand in Alberta, some of this wood pellet production in BC will likely be reallocated away from the EU. Indeed, our results indicate that, in light of the pending performance standard on coal-fired power plants in Canada, as much as 500,000 tonnes of BC wood pellets could be shipped to Alberta. This represents approximately 25% of 2012 wood pellet shipments from Canada to the EU.

Since wood pellet producers will export to those regions with the highest prices for wood pellets, after shipping and handling costs, the re-allocation of half a million tonnes of BC pellets from the EU to Alberta will likely have an impact on global wood pellet markets. However, the EU has been diversifying its suppliers of wood pellets in recent years, with the U.S., Russia, and parts of Asia and South America increasing shipments to the EU. Combining this with the fact that Canada represented less than 10% of total wood pellet supply to the EU, the impact on prices is likely to be small. Future research into the origins of wood fiber used to produce pellets, and global wood pellet markets, is required to answer this and other questions. What is clear nonetheless is that rapidly rising demand for biomass energy will have important repercussions for forestry and other sectors, including energy.

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