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The economics of tidal stream and wind power: an application to generating mixes in Canada

Abstract

Renewable wind and tidal energy are introduced into electricity grids to determine the effect on existing generators, the costs of reducing CO_2 emissions, and the benefit of including predictable tidal energy as a means of reducing the negative impacts associated with variable wind. Depending on the generation mix, costs of electricity could increase by 73% to 150% at renewable penetration rates of 30%, while associated costs of reducing CO_2 emissions range from $97.47 to $1674.79 per metric ton of CO_2. The introduction of tidal power only reduces intermittency-related costs slightly.

Keywords: wind and tidal power, carbon costs, electrical grids, mathematical programming.
JEL Classification: Q54, Q41, C61.

Introduction

Many electricity system operators are investing in renewable energy assets because of the need to reduce CO_2 emissions from traditional thermal generating sources. In British Columbia, Canada, for example, the provincial government has committed to increase wind, tidal, run-of-river and biomass generating capacity while permitting no new investment in fossil-fuel generation. Even though more than 90 percent of electricity is currently generated by large-scale hydro and other renewable sources, provincial greenhouse gas emissions are to be reduced by 33% from the 2007 level by 2020 and by 80% by 2050[1]. However, the provincial load is expected to increase by 45 per cent over the next two decades, and this cannot possibly be met by heritage hydro capacity (Murphy and Jaccard, 2003). Without further investments in renewable energy, the province will have to rely on fossil fuels, especially on recently discovered massive reserves of shale gas in north-eastern BC, although this is considered undesirable[2].

Biomass energy is a potential source of renewable energy, but research indicates that it is costly to harvest and that biomass fuel is economically feasible only if residuals become available as a result of commercial harvesting for lumber production (Stennes et al., 2010). As a promising large-scale option, expansion of run-of-river generation has run into political obstacles in British Columbia, while solar energy is less attractive due to its high cost and BC's northern location (with solar power least available in winter when demand is greatest). Installed wind generating capacity has increased rapidly in North America and elsewhere, including British Columbia (GWEC 2010). However, wind power output is highly variable and unpredictable, which, in the absence of storage, requires greater investment in reserve capacity. Wind variability also imposes higher operating costs on extant generators due to more frequent stops and starts, and/or higher per unit costs associated with production at below optimal levels associated with increased ramping of production (Prescott and van Kooten, 2009; Prescott et al., 2008; Liu et al., 2005; Pitt et al., 2005). It also makes it difficult to manage the grid to maintain stability (Lund, 2005).

Problems with wind intermittency can be mitigated to some extent if 'excess' wind power at times of low demand can be 'stored' behind a hydro dam, and then used to level the load facing extant thermal generation at times of high demand. While a system with large hydro capacity would seem ideal, CO_2 mitigation can only occur if there is sufficient thermal generation in the mix to prevent wind from simply substituting for hydropower or other renewable energy sources – there are no emissions reductions if one non-emitting source replaces output from another (van Kooten, 2010). However, generation mixes are not optimal and many systems lack hydro storage capability, while other forms of storage are simply too expensive.

Given the variability and unpredictability of wind power output, one might ask whether the introduction of a more predictable, less variable source of renewable energy into the power system might mitigate the problem of wind, or at least reduce grid operating costs. The purpose of this study is to investigate whether the inclusion of regular and perfectly predictable tidal power can reduce grid management difficulties when intermittent power is introduced into an electricity grid. In particular, can the introduction of tidal power alongside wind re-

[1] Bill 17 – 2010, The Clean Energy Act, 2nd Session, 39th Parliament, Province of British Columbia as viewed May 5, 2010 at http://www.leg.bc.ca/39th2nd/1st_read/gov17-1.htm.

[2] The Clean Energy Act leaves open the possibility of developing the highly contentious Site C dam on the Peace River, which will add 900 MW of generating capacity, but precludes further hydro development on rivers other than the Peace and Columbia. Yet, the province intends to become a major exporter of renewable energy.

duce the costs of mitigating climate change as penetration of these renewable energy sources into an electricity grid increases?

To investigate this problem, we employ a linear programming model that simulates an electricity grid where various generating assets (nuclear, coal, gas, hydro, etc.) are required to meet a demand profile. The methodology is described by Weber (2005) and van Kooten (2010) for the case of wind only, although it is a simple matter to add tidal power if data are available. Model outputs include the allocation of power generation by fuel type, costs and, importantly, the unit cost of CO_2 mitigation when renewable wind and tidal energy are introduced into an electricity grid. By examining different generating mixes, we can quantify which pre-existing generating mix benefits most from the inclusion of tidal and wind power.

In the next Section, we discuss the development of tidal stream power, how it works and what methods are used to establish the energy potential from a specific site. Because similar methods apply to the construction of a wind power output profile, and wind energy is discussed elsewhere in the literature, we spend much less time on this component. In Section 3, we provide data on tidal and wind power output, describe the generating mixes and load profile to be met, provide estimates of generating costs, and discuss the mathematical programming model in more detail. Then, in Section 4, we examine model results under various scenarios and draw conclusions about system costs and displaced emissions depending on the generating mix. We conclude by outlining some possible non-marketed values of tidal stream power and encourage subjective discussion into why these types of renewable energies are being promoted.

1. Tidal power: resource potential and extractable power

The extraction and conversion of tidal energy is not a new concept. Tide mills have been used to grind grains for nearly a thousand years, while barrage tidal power systems have been around since the 1960s (Blanchfield, 2007). Barrage systems use the potential energy from the difference in height between high and low tides by holding high-tide water in a reservoir and releasing it through a generator once the tide has receded. The largest barrage station is La Rance in St. Malo, France, with an installed capacity of 240 MW. The Annapolis Royal Generating Station in the Bay of Fundy, Nova Scotia, has been in operation since 1984 and has an installed capacity of 20 MW (Dadswell et al., 1986). The Bay of Fundy project had been opposed because of its high costs and negative environmental impacts (e.g., soil erosion, damage to aquatic life), but remains the only tidal generating station in North America, except for some prototypes.

Calculating the potential extractable power from ocean currents is subject to large uncertainty. There is controversy over conflicting estimation techniques at specific sites due to the way mathematical formulae include or exclude site characteristics, such as bottom composition, the size of the channel and different turbine spacing patterns. None the less, an extensive literature review by Black and Veatch (2006) estimated the global potential tidal energy capacity at 450 GW, total Canadian potential at 42 GW (equivalent to about one-third of Canada's total generating capacity from all sources), and British Columbia's potential at about 3000 MW (3 GW), which is equivalent to about 22% of the province's generating capacity[1].

Tidal stream power works much like wind power, but with large turbines installed underwater to harness the kinetic energy supplied by tidal currents rather than the wind. Tidal heights vary depending on a combination of lunar cycles of approximately 12 and 24 hours, 14 and 28 days, and half year and year, culminating in an 18.6-year cycle. Tidal currents vary with tidal heights so that, at any location, there will be periods when the water is still, and times when it reaches its highest velocities. Yet, the advantage over wind is that tides are regular and totally predictable, and may thus be more appealing to system operators seeking to balance supply and demand in any given period.

Tidal heights vary depending on a combination of lunar cycles of approximately 12 and 24 hours, 14 and 28 days, and half year and year, culminating in an 18.6-year cycle. Tidal currents generally vary with tidal heights so that, at any location, there will be periods when the water is still, and times when it reaches its highest velocities. The tides vertical rise and fall of water is related to the horizontal flow known as tidal currents (Bowditch, 1977). The velocity of the currents can be forecast with a high degree of accuracy based on over a hundred harmonic constituents, the shape of the seafloor, and the area of the restricting channel (Blanchfield, 2007). The velocity of the moving water is the dominating factor determining how much power an underwater turbine can generate.

[1] BC Tidal Energy Corporation plans to install at least three 1MW turbines onVancouver Island near Campbell River (Fraenkel, 2006).

Although tidal movements are predictable, currents are intermittent and the power that is actually generated at any one location and supplied to the grid can range between zero and the maximum rated capacity of the turbine assuming that the currents are strong enough to allow the turbine to reach its maximum capacity (Figure 1). The percentage of this maximum rated capacity that would actually be available over the year (the capacity factor) can range from 8% to 30% depending on the site (Fraenkel, 2006).

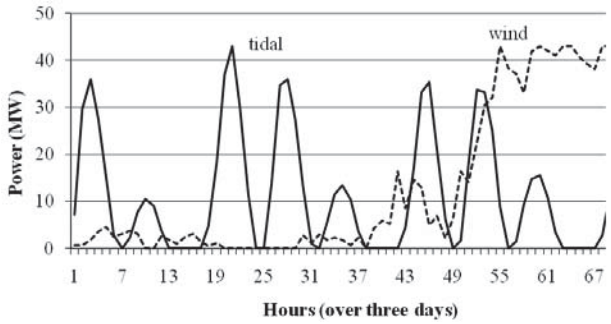

Fig. 1. Tidal versus wind power output

Due to the intermittency of power, a storage device would be desirable to smooth-out dispatch or make the power available when it is needed. Potential storage technologies involve traditional batteries, fuel cell systems, compressed air energy storage plants, and pumped-hydro (pumping water into a reservoir). Unfortunately, none of these storage devices are financially feasible to implement on a large scale at this time.

An alternative to storage involves tapping more than one location for tidal power exploitation since the currents in one place may be flowing when the water is slack in a nearby location, and vice versa. The 'front' of the tide advances up a bay so high tide at the head of the bay can be hours after high tide near the mouth. Therefore, if you have two generators, one can run while the other is in still water and, theoretically, a network of turbines could be planned to ensure that there is always one turbine spinning. This type of strategic planning has not been examined in detail to date. We address this issue to some extent by using data from two very different locations with different tidal movements.

Black and Veatch (2006) used case studies from Triton Consulting Ltd. (2002) to estimate the costs and extraction possibilities of two sites: Discovery Passage and Race Passage on Vancouver Island. The study estimated the extraction possibilities at Discovery Passage to be 800MW (1400 GWh per year) at a cost of 11¢/ kWh, while the smaller Race Passage site had a potential capacity of 43 MW (76 GWh per year) that could be extracted at a cost of 25¢/kWh. For the purpose of our model, we employ tidal current velocity data from these two sites.

For the purposes of the current study, we consider tidal turbines anchored to the seafloor at least 15 meters below low tide so as not to interfere with shipping. We employ information from a British company, Marine Current Turbines, which developed the utility-size 'SeaGen' tidal turbine, which consists of a twin-rotor turbine that incorporates a system for raising the rotors and power train above the surface of the water for maintenance purposes, eliminating the need for divers or submarines. For our application, we assume a turbine with a rotor diameter of 15 m, turbine efficiency of 20%, a nameplate capacity of 500 kW per rotor (1 MW capacity turbine), a generator efficiency of 30%, and 'cut in' and 'cut out' velocities (when the turbine cannot generate power) of 1 m/s and 3.6 m/s, respectively. Since the rated capacity of our turbines is 1 MW, we assume that 100 turbines are to be installed at Discovery Passage and 43 turbines at Race Passage, which is less than or equal to the maximum extractable energy for the sites as estimated by the Triton Consultants Ltd. (2002).

Although ignored here, environmental impacts should be considered when determining extractable energy from specific sites. For example, a case study on Haida Gwaii revealed that the maximum extractable power from Masset Sound is about 54 MW (Blanchfield, 2007), but extracting this amount would decrease the maximum flow rate through the channel by approximately 40% from its undisturbed regime. The consequences of altering the natural currents are unknown but would most likely affect the spawning and migratory patterns of aquatic life. Blanchfield (2007) determined that the tidal regime could be kept to within 90% of the undisturbed state by limiting the average extracted power to approximately 12 MW.

For our modeling scenarios, we use recorded current velocities to derive the extractable power. The basic estimation technique is the same as that used for wind turbines, which uses the basic law of thermodynamics to derive the theoretical maximum energy that can be created from a rotor when a fluid moves through it at a certain speed. The equation can be expressed as:

$$E = ½ \times \rho \times S \times v^3, \quad (1)$$

where E is the power delivered to the turbine, ρ is the fluid's density, S is the total swept area of the rotor blades, and v is the velocity of the fluid. To determine the actual power P at the specific sites, we extract only a fraction of the available kinetic energy given by the 'Betz limit' – only a maximum

of 59.3% of the wind's kinetic energy potential can potentially be extracted. This limit accounts for the fact that we need to keep the tidal currents moving past the rotor after each stage of energy extraction to allow the incoming water to enter the rotor at a speed that ensures the greatest overall extraction over the time frame. Based on previous work by Blanchfield (2007), we use:

$$P = N \times \eta \times \mu \times ½ \times \rho \times S \times v^3, \quad (2)$$

where N is the number of turbines at the site (100 at Discovery Passage and 43 at Race Passage), η is the turbine efficiency (20%), and μ is the theoretical extractable power affected by the bottom drag and the ability of the water to 'stream around the turbine' (30%). The density of water is assumed to be 1030 kg/m^3 and the rotor diameter is 15 m based on Marine Current Turbines design.

2. Electricity grid model that integrates tidal and wind power

The costs and benefits of incorporating tidal power into an electricity grid depend not only on the costs of installing, operating and maintaining the individual turbines, but also on how the entire generating system is affected by the tidal generated power penetration (tidal capacity as a percent of peak system load). Following a similar methodology used in studies of wind power (Weber, 2005; Lund, 2005; Prescott et al., 2007; van Kooten, 2010), we use a mathematical linear programming model to determine the impacts of integrating tidal power along with wind power into electricity grids. The model minimizes system costs of meeting the 2006 BC electricity load by optimally choosing the power-makeup between the available sources. The model results provide the megawatt hour costs of tidal and wind integration; the amount of carbon dioxide (CO_2) that can be displaced by these renewable energies; and the unit cost of CO_2 mitigation. These costs and benefits will depend on the pre-existing mix of power sources. We consider three generating mixes, and thereby quantify which pre-existing generating mix benefits most from the inclusion of tidal and wind power. Each generating mix is required to meet the same load profile, which is that of British Columbia.

In our model, we assume that the grid will take all of the available electricity produced by the renewable energy sources. That is, wind and tidal power are given priority over other sources – they are considered 'must run' or non-dispatchable. The model optimizes over a full year using an hourly time step. The system operator allocates output across generating sources to minimize the overall cost in every hour over the year allowing a 5% 'safety allowance.' Included in the objective function are: fuel costs, variable operating and maintenance (O&M) costs, and fixed O&M costs. The model is constrained by the individual plant's capacity, ramping up and down rates, and the necessity of meeting the load demand in every given hour of the year. We assume rational expectations in the sense that the system operator has full knowledge of demand and power availability within the 5% safety allowance. The model is solved in an Excel-Matlab-GAMS environment, with Matlab retrieving data from Excel and calling GAMS to solve the linear programming problem.

3. Tidal, wind and load data

Tidal current speed data for Discovery Passage and Race Passage on Vancouver Island were obtained from the Institute of Ocean Sciences at the federal Department of Fisheries and Oceans. They calculated the current velocities by utilizing past observations and generating 'hindcast' predictions for 2006 using harmonic constants that the Canadian Hydrographic Service uses
to produce its tide tables. The velocity profiles of the two sites vary considerably: the maximum speed for Race Passage is 3.59 m/s, while it is 7.527 m/s at the Discovery Passage site. Since extractable energy is directly related to the cube of the velocities, this difference implies that potential extraction varies radically with site location. However, given the state of the art of technology, generators are not now able to capture the kinetic energy of current speeds greater than 3.6 m/s, so we restrict power output when currents exceed 3.6 m/s. Other considerations are that the model cannot exceed the rated capacity of the site (100 MW for Discovery Passage and 43 MW for Race Passage), and we assume that the generator will switch on (the 'cut-in' rate) when the current speed exceeds 1 m/s. We then apply formula (2) to determine the extractable power. An example of the tidal power output profile is provided in Figure 1.

Wind data are from four sites in BC's Peace River region and one site (Pulteney Point) on Vancouver Island (van Kooten, 2010). The total installed capacity is assumed to be 218 MW, which is consistent with previous modeling scenarios. We also assume that wind is perfectly predictable within the scope of our model, which makes our results all the more portent. A profile of three days of wind power output is provided in Figure 1.

Hourly load (demand for electricity) data for British Columbia was provided for 2006 by the BC Trans-

mission Corporation, which plans, operates and maintains the province's publicly-owned transmission system[1]. The wind and tidal nameplate generating capacities were normalized to the maximum peak load for 2006 of 11,039 MW (excluding the safety allowance), thus enabling us to simulate scenarios with different penetration rates. The renewable penetration refers to the ratio of the wind and tidal installed capacity divided by the peak system load. We chose penetration rates of 10%, 20% and 30%. This will quantify the effects of increased renewable penetration into the gird.

4. Generation mixes

We investigate the impacts of increasing renewable energy penetration into various generating mixes, which we normalize to meet the 2006 load for British Columbia. This allows us to see the differences in costs and emission reductions that arise depending on the overall portfolio of energy sources. We use the 2006 generating capacity mixes for BC, Ontario and Alberta, which employ five traditional generation technologies: combined-cycle gas turbines (CCGT), combined-cycle petroleum (CCP), pulverized coal-fired generation, large-scale hydropower, and nuclear power. We also introduce biomass into all the mixes at a modest rate of 0.5%, which is consistent with trends for all provinces.

British Columbia generated 90% of its power from hydro sources in 2006, while the remaining 10% was a mixture of natural gas, diesel and biomass. The province has a transmission interconnection with Alberta, which generation mix consists primarily of coal (64%) and gas (21.5%), with the remainder hydro, wind and biomass. Finally, Ontario's generating mix includes coal and nuclear generating capacity. The generating mixes as used in this study are summarized in Table 1.

Table 1. Energy source portfolios by province

Source	BC	Alberta	Ontario
Hydro	89.5%	9.7%	20.0%
Nuclear	0%	0%	44.0%
Coal	0%	63.8%	19.0%
Gas	10.0%	21.5%	11.5%
Petroleum	0%	4.5%	5.0%
Biomass	0.5%	0.5%	0.5%

Source: Environment Canada (2006).

Due to fluctuating water levels in hydro reservoirs, as well as low prices in the US and Alberta energy markets, British Columbia is sometimes a net importer of electricity. However, when reservoirs are full the generating capacity of British Columbia exceeds peak demand. The actual generating capacity in 2006 was 13,750 MW (Environment Canada, 2006), but recall that it varies with water availability; this capacity provides an 18.6% reserve margin for the peak load of 11,591 MW (including safety allowance). As we assume that hydro capacity is constant throughout the year, we simply model the overall generating capacity as being 15% less than actual capacity, and carry this assumption over into all three generating mixes.

4.1. Ramping constraints. Thermal generators take time to ramp-up to full capacity or ramp down to a lower operating level when they are not needed. Efficiency losses arise when renewable tidal and wind power are introduced, because the ramping limits of the thermal generators may lead to excess generation in some periods when there is more than sufficient wind and tidal power available. Further, some traditional capacity needs to remain on line as spinning reserve in case output from wind and/or tidal sources is not available. The thermal sources are modeled with ramp rate constraints that represent the time it takes for the generators to increase or decrease their power output to the desired levels for production[2]. We employ simple ramp constraints. Coal and nuclear power plants are assumed to take three hours to fully ramp up or down, but output is not permitted to fall below 50% of capacity for technical and costs reasons. CCGT, CCP and biomass generators are assumed to take two hours to ramp up or down.

4.2. Costs. Costs for wind, combined-cycle gas and coal are taken from a report prepared by Americas Limited for the Alberta Electric System Operator (AMEC) in October 2006 (AMEC Americas Limited, 2006). Costs of hydropower and the thermal sources are summarized in Table 2. The fuel costs are based on prices of fuel per ton of oil equivalence (toe) and then adjusted by their maximum efficiency in use (second last column in the table) and the exchange rate. The calculation is as follows:

$$\text{Cost (\$/MWh)} = \text{US\$/toe} \times 1000 \text{ toe}/11630 \times \times \text{MWh} \times \text{C\$0.98/\$US} \times \text{efficiency}, \quad (3)$$

where the final monetary unit is in Canadian dollars[3]. All costs are based on 2006 estimates and may be higher than current costs.

[1] In 2010, the government re-integrated the BC Transmission Corporation into BC Hydro, which the publicly-owned electricity system operator.

[2] Some coal generating plants can ramp up and down rather quickly, but the types installed in Alberta and Ontario were designed solely as base-load plants.

[3] The following relationships are used: Mtoe = 1,000,000; toe = 11630 GWh; 1 GWh = 1000; MWh = 3600 GJ; 1 GJ = 278 kWh.

Table 2. Electrical generation costs and efficiencies by source

Source	Variable O&M ($/MWh)	Fixed O&M ($/KW)	Maximum efficiency	Fuel cost ($/MWh)
Hydro	0	14.5	100%	1.1
Nuclear	12.0	35.0	40%	2.3
Coal	6.0	39.9	38%	4.5
CCGT	5.0	10.9	49%	16.9
CCP	6.0	12.9	40%	27.0
Biomass	2.8	10.0	35%	14.7

In the model, generators are arranged in merit order according to marginal cost. Thus, as renewable power enters the system, the model will first seek to eliminate power production from petroleum plants (CCP), followed in order by CCGT plants, biomass plants, coal plants, and finally from nuclear and hydro facilities. Ramping and other constraints, including the need to meet power at some future time, can prevent this order from being implemented in this way. Notice also that the model will attempt to reduce output from biomass facilities before it reduces output from coal plants, which leads to the substitution of one renewable source (biomass) by another (wind, tidal). However, biomass and CCP capacities are small, while CCGT is required mostly around peak demand periods. Thus, coal plants will be affected as wind and tidal power penetrate the grid, particularly during off-peak times.

4.3. CO_2 emissions. Carbon dioxide emissions are a direct function of the type of fuel burned and the generating plant's efficiency. Mathematically this can be expressed as:

$$tCO_2 = \text{Emission Factor/Average Plant Efficiency}, \quad (4)$$

where the emission factor is equal to 0.346 tCO_2 per MWh for sub-bituminous coal, 0.28 tCO_2 per MWh for oil, and 0.202 tCO_2 per MWh for natural gas[1]. The plant efficiencies vary depending on generator make-up and age of the facility. Thus, we assume the following based on aggregation averages: 0.38 for coal, 0.49 for gas and 0.40 for oil.

5. Model results

We first examine how demand is satisfied without wind and tidal power in the grid. A total of 64.63 TWh (64.63 million MWh) are generated from all sources in the model, thus satisfying the 2006 BC load. This compares with actual recorded generation for the year (with a reliability factor of 5%) of 64.09 TWh. To minimize the cost of generating this electricity, the model chooses different allocations of dispatch across all sources depending on the generating mix. For example, using the BC mix, the model chooses to employ 97.4% hydro with the remaining generation covered by gas and biomass. This is almost exactly the same as Environment Canada data for 2006 which show that 96.6% of BC's demand is satisfied using hydro generation.

Traditional sources of fuel must supply power in a fashion that follows the cycle of demand over the day, including peak demand periods. When wind and tidal power are added to the mix, traditional generating sources are forced to track a much more irregular pattern of power generation, with generators ramping up and down more frequently, which leads to inefficiencies in the overall generating system.

In British Columbia, in the absence of renewable tidal and wind energy, hydro power satisfies almost the entire load, with gas used in periods of peak demand when hydro capacity is exceeded. Demand is satisfied by different power sources once the tidal and wind power are added to the British Columbia generating mix. In particular, the wind and tidal power mostly displaced hydropower, but it remains necessary to employ gas generation during some very limited peak demand periods.

An Alberta-type generating mix relies mainly on thermal coal and natural gas. In the absence of wind and tidal power, changes in gas generation closely follow changes in demand, while coal generation ramps up during periods of peak demand. Once tidal and wind power are added to the grid at a penetration of 30% (relative to peak demand), changes in gas generation no longer mirror the load and become more sporadic. It is no longer necessary to ramp-up the coal generator during peak demand since tidal and wind power are able to cover the excess generation needed in this period. Similar results hold for an Ontario-type mix, although at very high rates of renewable penetration nuclear plants are affected and this could spell trouble as nuclear plants do not ramp up and down as readily as assumed in the current model.

6. Cost results

Capital costs of wind farms are assumed to be $600,000 per MW of installed capacity for wind, and $1,800,000 per MW for installed tidal capacity. These costs are quite modest compared to actual costs as we expect a decrease in costs as technology becomes more efficient and/or economies of scale are realized. Capital costs are amortized over 25 years at an interest rate of 6%. The fixed O&M costs are assumed to be $45,320 per installed MW for wind

[1] See, http://bioenergy.ornl.gov/papers/misc/energy_conv.html for energy-carbon conversions. Multiply by 44/12 to convert from carbon to carbon dioxide. Given 1 TJ = 0.2778 GWh and the number of metric tons of carbon (tC) released per TJ of energy, the following conversion is used in the analysis: $tC/TJ \times 44tCO_2/12tC \times TJ/0.2778GWh \times GWh/1000MWh = = 0.0132\ tCO_2/MWh$.

and $61,714 per MW for tidal – the latter based on the UK tidal data (Black and Veatch, 2006). Although there is no cost for using wind and tidal currents as fuel, capital costs will likely grow as renewable penetration increases because sites of increasingly poorer quality will need to be developed. Capital costs for existing generators are not taken into account as this generating equipment is already in place.

Electricity costs per megawatt hour are calculated by summing all the fuel, variable and fixed O&M costs of the thermal sources individually for each hour and adding them to the O&M costs and annualized capital costs of the wind and tidal farms. This is then divided by the sum of all electricity produced over the year. Since capital costs for the traditional thermal sources are ignored, the resulting system cost per MWh will be biased downward. Therefore, we record the *change* in cost as penetration increases. This allows us to conclude which generating mixes experience the sharpest change in electricity costs when tidal and wind power are added to the portfolios.

The change in the cost of electricity is provided in table 3 for each generating mix. Not unexpectedly, the BC mix exhibits the largest increase in cost ($/MWh) as tidal and wind energy are added to the portfolio. At a penetration rate of 10%, the cost increases from its base (no wind or tidal energy) amount by 48%. This grows to 150% of base cost when penetration reaches 30% of load. This is expected because tidal and wind generation simply replace cheap hydro. Therefore, fuel costs are not displaced and the capital cost of the renewable installation increases with penetration.

For an Alberta mix, costs increase by 32% over the base level with 10% penetration and then double from base at 30% penetration. Tidal and wind generation are able to displace some of the fuel costs of traditional fuels such as coal, but the capital costs outweigh the reductions in fuel costs at all levels of penetration investigated here.

For a generation mix such as that found in Ontario, costs increase the least as intermittent power penetration increases. Costs rise by only 23% from the base level with 10% penetration, while they increase to 73% when renewable penetration increases to 30%. This demonstrates that renewables manage to displace some thermal sources, such as gas and coal, but the necessity for high expenditure during initial installation results in an overall increase in costs of generating electricity for the system.

Table 3. Cost of electricity for three generating mixes with wind and tidal penetration

Tidal/wind penetration	Electricity cost by generating mix ($/MWh)			Cost ratio by generating mix		
	BC	Alberta	Ontario	BC	Alberta	Ontario
0%	4.22	6.12	8.27			
10%	6.25	8.06	10.21	1.48	1.32	1.23
20%	8.35	10.10	12.10	1.98	1.65	1.46
30%	10.54	12.25	14.27	2.50	2.00	1.73

In Table 3, the cost of generating electricity is provided in dollars per megawatt hour with and without tidal and wind power penetration. Since the annualized (at 6%) capital costs of the wind and tidal facilities outweigh the saved fuel cost in every generating mix, we encounter an increase in costs as penetration rises for all three generating mixes.

7. Reduction in CO_2 emissions

Policymakers will be primarily concerned with the amount of CO_2 emissions that renewable energy is able to displace and with the costs of reducing such emissions. We first consider the extent to which wind and tidal power can offset CO_2 emissions based on our model. This is done by calculating the sum of all electricity produced by the various generating types multiplied by their corresponding emission factors for each of the various tidal and wind penetration rate scenarios, and subtracting from the base case:

$$\text{CO}_2 \text{ Reduction} = \sum_{i=1}^{N} GS_i \times EF_i - \sum_{j=1}^{N+\text{Wind+Tidal}} GS_j \times EF_j , \qquad (5)$$

where GS_k is the sum of all electricity generated by source k and EF_k is the emission factor for that type of generation. The results are provided in table 4 for varying renewable penetration rates. As tidal and wind power are added to the portfolio, the greatest CO_2 emission savings occur early on as the 'dirtier' fuels get displaced first. However, the magnitude and rate of this reduction varies with the original generating portfolio and the penetration of the renewable power. Carbon dioxide emissions are produced as a byproduct of generating electricity with fossil fuels. Depending on the original generating mix, the amount of emissions produced will vary considerably when generating the 64.63 TWh of electricity that is needed to satisfy the model's load. Prior to the inclusion of tidal and wind energy, the BC mix only generates 0.9 Mt of CO_2 while the Ontario mix generates 18.5 Mt and the Alberta mixture 42.3 Mt. This is what we would expect to find considering the generating mixes. Since BC produces most of its energy from hydro, its generating mix would produce much less CO_2 than the coal-dominated Alberta mix, or the Ontario mix that in-

corporates a range of sources. According to statistics from Environment Canada (2007), British Columbia produced 1.2 Mt of CO_2 during 2006 while Alberta and Ontario produced 115 Mt and 72 Mt, respectively. Therefore, our model results are comparable to the emissions produced in each province during 2006 once demand is factored down to the 2006 British Columbia load.

Table 4. CO_2 emissions with tidal and wind power and rate at which emissions are reduced

Tidal/wind penetration	Total CO_2 emissions (megatonnes)			Incremental change from base emissions		
	BC	Alberta	Ontario	BC	Alberta	Ontario
0%	0.92	42.30	18.51			
10%	0.72	40.44	17.30	-21.6%	-4.4%	-6.5%
20%	0.68	38.66	16.48	-26.1%	-8.6%	-11.0%
30%	0.68	36.97	15.51	-26.1%	-12.6%	-16.2%

Note: For a load pattern similar to that of British Columbia in 2006, with peak demand of 11,039 MW.

For BC's generating mix, the amount of displaced CO_2 declines substantially as the penetration rate of the renewable power increases. That is, the results display diminishing returns for abated emissions as renewable penetration rates increase. Thus, adding a small amount of tidal power to the BC portfolio (10% penetration) displaces a large percentage of total system CO_2 (21.6%), but adding more renewable power provides much fewer benefits in terms of abated emissions (less than 1%) – one form of renewable energy (wind/tidal) substitutes for another (water). Yet, compared to the other generating mixes, the initial introduction of a 10% renewable penetration rate leads to the sharpest relative fall in emissions for the BC mix. Consistent with actual 2006 data for British Columbia, about 3% of generation comes from natural gas while hydropower and biomass account for the remainder (ignoring imports).

Once renewable power is introduced, natural gas is replaced by renewable energy during many but (crucially) not all of the peak demand hours. Thus, renewable wind and tidal energy cannot eliminate the need for peak gas generation regardless of penetration level because of the intermittent nature of these energy sources. For the BC mix, gas generation remains almost constant as a percentage of overall generation between 2.50% and 2.98%. Due to the intermittency of the renewable power, there are still periods where no or little wind or tidal power is produced and gas must be used to cover the excess of demand over hydro supply. Perhaps, by exploiting a variety of sites as penetration increases (as opposed to simply increasing installed capacity at the sites identified in this study) periods when no wind or tidal power is generated could be eliminated, although research suggests this is difficult to do (see van Kooten, 2010). However, exploiting a multitude of sites is probably unrealistic in any case and would increase O&M costs as well as the costs associated with transmission lines.

For the Ontario generating mix, renewable tidal and wind energy are able to decrease CO_2 emissions by roughly 5% as the renewable penetration is increased by 10%. Thus, emissions will fall as renewable penetration increases in this type of generating mix.

For the Alberta generating mix, there is a noticeably smaller change in the extent to which wind and tidal resources displace CO_2 as renewable power penetration increases. None the less, the absolute fall in emissions is greater than in other mixes because clean renewable power displaces large amounts of coal. Although the emission-reduction benefits display relatively constant returns to scale for Alberta scenarios, benefits will likely decline sharply at greater penetration rates as increased ramping up and down will occur causing coal-fired plants to operate less efficiently. Overall, however, model results indicate that renewable tidal and wind power are able to mitigate substantial amounts of CO_2 emissions for this type of generating portfolio.

7.1. Costs of reducing CO_2 emissions. We calculate the cost of reducing one tonne of CO_2 (tCO_2) as the difference in our objective function (plus the capital costs of the tidal and wind farms) with and without renewable penetration, divided by the displaced CO_2 emissions when the renewable is introduced, as determined from equation (5). Results are provided in Table 5. For comparison, CO_2 emissions have traded on the European market for upwards of nearly \$40/tCO_2. The government of British Columbia implemented a carbon tax on July 1, 2008 that started at a rate of \$10/tCO_2 and rises by \$5 a year for the next four years to reach \$30/tCO_2 by 2012 (British Columbia Ministry of Finance 2008). Compared to this benchmark, the model's predictions of the costs of mitigating CO_2 by introducing tidal power are high. From a purely financial prospective it would be more efficient to buy carbon credits or pay the tax.

Table 5. Cost of reducing CO_2 emissions through tidal/wind power

Renewable penetration rate	BC	Alberta	Ontario
	$ per tonne of CO_2		
10%	659.71	133.88	103.67
20%	1112.56	104.53	121.89
30%	1674.79	97.47	129.01

As expected, the cost of reducing one tonne of CO_2 by installing tidal and wind power in the BC generating mix is the highest since the renewable power mostly displaces hydro power, which is considered emissions free in our model. Only 0.92 Mt of CO_2 are produced annually in the BC mix, and that comes mainly from the operation of a gas plant during peak hours. At low penetration levels, renewable power is able to replace some of this gas, but it becomes increasingly more difficult to do so at higher penetration rates since the peaks of electrical demand occur at moments of slack water or calm winds. Therefore, the cost of displacing emissions rise sharply to $1674.79 at penetration rates of 30%.

For the Alberta and Ontario generating mixes, the emission abatement costs are more reasonable with the highest price of $133.88/t$CO_2$ and the lowest price of $97.47/t$CO_2$. Although these costs are still higher than the benchmark of $30/t$CO_2$, it might be possible to profit from intermittent wind (and tidal) energy in mixes with high amounts of coal as costs come down or prices of carbon permits rise.

Conclusion

In this paper, we used a (dynamic) linear programming model to determine the effects of tidal and wind power integration into grids with different mixtures of conventional generating capacity. Although the pattern of available tidal stream power is more cyclical and predictable than wind power, attempts to harness power from only a few locations lead to irregular supply of power to the grid. Since these intervals often fail to coincide with the pattern of rising and falling electricity demand, electricity will be wasted within the generating system due to the inability of thermal sources to adjust their power output instantaneously when the renewable power becomes available. This inefficiency leads to an added cost of tidal and wind power that is often neglected in considering the costs and benefits of renewable energy projects.

Results indicate that wind and tidal power do have the ability to displace a percent of dirtier fuels and their corresponding emissions, but that ability depends heavily on the portfolio of generating sources. Systems reliant primarily on hydropower benefit the least from the adoption of tidal and/or wind energy. Renewable power is not always available when it is needed: during non-peak hours, renewable energy simply replaces inexpensive and clean hydro thereby providing no improvement in terms of emissions reductions. There exist some periods when the renewable energy is able to replace gas, but only at the same rate that hydro generation is also reduced. That is, renewables are only able to reduce the overall amount of electricity that must be generated by the other sources, but they are not able to decrease the relative relationship of gas and hydro.

For a generating mix with a higher percent of coal, emission-reduction benefits are greater and costs of reducing emissions are lower, but only as long as there is enough peaking (gas) plant capacity to cover periods when base-load coal plants are ramping up or down. The presence of nuclear power does not change the basic results, except that it is much more difficult in practice to ramp nuclear plants. Further, when renewable energy substitutes for nuclear energy, the CO_2 savings are essentially non-existent.

Usually when policy makers consider adopting renewable energy they will take the capacity factor of the renewable source and assume that it will displace a proportional amount of existing generating capacity on a one-to-one basis. They may even assume that the renewable power will displace generation from the dirtiest source one-for-one. Our results clearly demonstrate the error in this way of thinking. Not only we can be not sure of which traditional sources will be displaced, but the displacement is non-linear because of the efficiency losses to the entire system.

Our results also indicated that wind and tidal stream power can be an expensive means of mitigating CO_2 emissions compared to purchasing emission offsets in carbon markets. This is particularly the case for tidal stream power if transmission lines need to be constructed to deliver power to markets. Transmission issues were not included in this analysis, as this is left to future research. However, it is also the case that the development of high voltage transmission capacity can alleviate some of the problems of integrating wind and tidal power into electricity grids. Transmission lines can change the generation mix into which renewable power is sold and they can facilitate the use of intermittent energy sources if they provide access to hydro storage, which could be the case if wind developments in Alberta, for example, are linked to hydro storage in British Columbia via enhanced transmission capacity. This is a subject for future research as it requires the use of game theory to obtain a feasible outcome.

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