Wind Power: The Economic Impact of Intermittency

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Abstract

Wind is the fastest growing renewable energy source for generating electricity, but economic research lags behind. In this study, therefore, we examine the economics of integrating large-scale wind energy into an existing electrical grid. Using a simple grid management model to investigate the impact of various levels of wind penetration on grid management costs, we show that costs of reducing CO_2 emissions by relying more on wind power depend on the generation mix of the existing electricity grid and the degree of wind penetration, with costs ranging from $21 to well over $1000 per tonne of CO_2 reduced. Costs are lowest if wind displaces large amounts of fossil fuel production and there is some hydroelectric power to act as a buffer. Hydro capacity has the ability to store wind generated power for use at more opportune times. If wind does nothing more than replace hydro or nuclear power then the environmental benefits (reduced CO_2 emissions) of investing in wind power are small.

Keywords: Wind power, carbon costs, electricity grids, mathematical programming

JEL Classification: Q54, Q41, C61

1. INTRODUCTION

Because of their ubiquity, fossil fuels have become the backbone of industrial economies, while the electricity supply infrastructure is their spinal cord. Burning of fossil fuels emits gases contributing to global climate change and local pollution, while dependence on oil and gas raises issues concerning supply security. For these reasons, countries seek renewable sources of energy, including in particular wind, solar and tidal forms that suffer from intermittency in supply that cannot easily be overcome through storage. Yet, wind is now the fastest growing renewable energy source for generating electricity (van Kooten and Timilsina 2009).

In this study, we focus on wind energy to examine the economics of integrating large-scale wind energy into an existing electrical grid, emphasizing in particular the costs associated with intermittency. Two approaches to estimating the indirect costs of wind variability can be identified. First, some researchers have focused on the costs of additional system reserves required to cover the increased variability of wind (Gross et al. 2003, 2006; Kennedy 2005). When wind generating capacity is installed on a large scale, greater system balancing reserves are required than would be the case if an equivalent amount of thermal or hydro capacity were installed, even after adjusting for the lower capacity factors associated with wind. If wind farms are placed over a large geographic area, then, for the same installed wind power capacity, the output would be smoother than if it were to come from a wind farm at a single site. Therefore, to overcome variability, it is necessary to locate wind farms across as large a geographic areas as possible and integrate their combined output into a large grid. Doing so will reduce the costs of wind power generation.

The second approach focuses on the implications that wind has on the management of an electricity grid and the costs of retaining system balance (Lund 2005). Because wind power is non-dispatchable, extant generators must be ready to dispatch power to the grid in the event of a decline in wind availability. Fluctuations in wind result in increased ramping-up and ramping-down of base-load generators, failure of slow-ramping facilities to follow variations in load, and more frequent starts and stops in the case of peak-load (open-cycle) gas plants, thereby leading to increased operating and maintenance (O&M) costs. While this problem could be mitigated by storage, no viable large-scale storage systems are currently available. Because of the storage problem, wind power is used most effectively in electricity grids that have large hydropower capacity. In that case, water can be stored in reservoirs by withholding hydro-electricity from the grid, but releasing water and generating electricity when there is no wind power.

The second approach is employed in this study. It is based on the notion that a suitable constrained optimization model of an electricity grid that assumes rational expectations (load and wind power availability are known beforehand) should project costs that are equal or lower to those based on rule-of-thumb requirements regarding additional reserves (Gross et al. 2006, 2007). The only difference is that a grid optimization model takes explicit account of the need to balance output from existing generators on the grid (see Maddaloni et al. 2008).[1]

We begin in the next section by examining the issue of integrating wind power

[1] The first approach for calculating reserves relies on known information about wind variability as much as the second approach.

into electricity grids in more detail, and developing a model for estimating the potential costs of integrating varying amounts of wind into grids with differing generation mixes. The results are provided in section 3. We find that a grid dominated by fossil fuel generating capacity but with adequate hydroelectric facilities that can store wind generated power at crucial times is optimally suited for investment in wind farms. Somewhat surprisingly, however, the costs of reducing CO_2 emissions are higher than socially desirable in all the cases we examine. Some concluding observations follow in section 4.

2. INTEGRATING WIND POWER INTO ELECTRICITY GRIDS

Consider how conventional generation capacity can be replaced by wind capacity while maintaining system reliability for a large, relatively isolated system (Love et al. 2003; Pitt et al. 2005). To do so, we employ hourly load data from the ERCOT (Texas) system for 2007 (2008), and wind data from sites located in western Canada. The ERCOT load data are standardized to a peak load of 2,500 MW (the ERCOT peak load/demand is 62,101 MW). Actual wind power output data are available on an hourly basis for sites in Alberta, while hourly wind speed data from BC Hydro (2004) are available for sites in north-eastern British Columbia. The two regions for wind data are chosen because they are both located immediately east of the Rocky Mountains where wind potential is very high, and are some 800-1000 km apart so that winds should not be highly correlated.

Wind speed measurements occurred at heights of 30 m and 50 m for the BC sites and can be converted to wind power. Wind power depends not only on wind speed but also on the height of the turbine hub, so measured wind velocity is adjusted using the following well-known relationship:

$$V_{hub} = V_{data} \times \left(\frac{H_{hub}}{H_{data}} \right)^{\alpha}, \tag{1}$$

where V_{hub} is the wind velocity (m/s) at the turbine hub height, V_{data} is the wind velocity (m/s) at the height it was measured, H_{hub} is the height of the wind turbine hub (m), H_{data} is the height (m) at which the data was measured, and α is the site shear component that is dependent on the type of ground surface on which the wind turbine is built. We derive wind power output using power curves for wind turbine products from ENERCON GmbH (2007), assuming a 2.3 MW, Enercon E-70 wind turbine with hub height of 95 m and 71 m rotator diameter, and $\alpha = 0.15$ in Equation (1).

The artificially created hourly wind power data for north-eastern BC and the actual wind power output data for southern Alberta are each adjusted to a single-2.3 MW turbine basis. The wind power information is summarized in Table 1. Data from each of the four northern wind sites are for a single turbine, so the combined data are divided by four. For sites in southern Alberta, hourly wind power outputs are divided by the total capacity (264 MW) of the seven wind farms in the analysis and multiplied by 2.3. The simple coefficient of correlation between the individual northern and southern sites varies between –0.078 and –0.011, implying little or no (negative) correlation. The correlation between individual northern sites varies between 0.435 and 0.847, while it varies between 0.780 and 0.833 for individual southern sites, implying positive correlations within regions but not across regions. Nonetheless, the data indicate that there are 18 hours when no wind power is available, despite the negligible correlation between northern and southern sites;[2] the maximum (standardized) wind power output for any given hour is 2.086 MW.

Table 1: Wind Penetration based on Western Canada Wind Sites

Site	Capacity (MW)	Production (GWh)	Capacity factor (%)
Sites in southern Alberta currently in operation			
Castle River #1	40	350.440	28.7
Cowley Ridge	38	332.918	7.4
Kettles Hill	9	78.849	27.4
McBride Lake	75	657.075	34.4
Summerview	68.4	599.252	34.9
Suncor Magrath	30	262.830	36.6
Taylor Wind Farm	3.6	31.540	18.8
Hypothetical sites in north-eastern British Columbia[a]			
Aasen	2.3	4.250	21.1
Bessborough	2.3	3.387	16.8
Erbe	2.3	3.603	17.9
Bear Mountain	2.3	7.044	35.0

Notes:
[a] Values are based on the output of a single 2.3 MW turbine, but it is possible to expand to 500 MW.
Source: Authors' calculations.

Since we are interested in a situation where some wind power is always available, we added a fifth wind source based on a wind measurement site on Pulteney Point on the north end of Vancouver Island, British Columbia (see Prescott et al. 2007). This site is some 850-900 km from the nearest site east of the Rockies. We calculated the wind power output for this wind site assuming an Enercon E-70 turbine, and combined the resulting power output with that calculated for the four sites in north-eastern BC. Again we standardized the output to the single 2.3 MW capacity turbine by dividing the

[2] Counting from the first hour in January, the hours with zero wind power output are 1691, 1692, 2299, 2336, 2338, 3176, 3823-3826, 4835, 6445-6450, and 7514.

resulting wind power output by five (as we now have data from five sites). Again we find hours when there is absolutely no wind power output, although only four hours in this case.[3] This illustrates a major problem: Given the diversity of locations and rather large distances between sites in western Canada, it is unlikely that any system that relies on wind power is going to be able to avoid times of zero wind power output. In our case, we rectify the situation by adding to our data the average wind power of the five BC sites, shifted forward by 24 hours. In this case, the minimum wind power output for any given hour is 0.005 MW while the maximum is 1.779 MW compared to 1.971 MW before adjustments.[4]

Load Duration and System Reserves

A load duration curve is determined by sorting the system load (demand) in each hour from highest to lowest. The minimum or base load is generally met by a base-load power plant such as a coal or nuclear thermal generating facility. In our example, plotted in Figure 1, the base load is 878 MW compared to a peak load of 2500 MW. Load following facilities may consist of base-load plants, although combined-cycle gas turbine (CCGT) plants and hydroelectric are more optimal load-following facilities. These would cover load somewhere between the base load of 878 MW and about 1400 MW – that is, about 550-650 MW of load-following capacity is required. The remaining capacity needs to respond much more quickly as it must meet peak power demands that occur at certain

[3] Hours 3823-3826 are without wind power output.

[4] This is similar to a problem discussed by Oswald et al. (2008): Weather systems affect very large geographical regions. It is possible for winds to be weak everywhere at the same time, even if monitoring sites are located a thousand or more km apart and separated by one or more mountain ranges.

times of the day and certain times of year. Open-cycle gas plants and hydropower stations are ideal peak load facilities.

A net load is constructed by subtracting wind output from demand. In Figure 1, we created net load duration curves for wind penetration rates of 10% and 30%, where wind penetration is defined as the ratio of installed wind capacity to peak load. The net load has to be met by conventional generators. Notice that the base load falls from 878 MW to 751 MW, or by 14.5%, for a wind penetration rate of 10%, but to 389 MW, or by 55.7%, for wind penetration of 30% (41.2% fall compared to the 10% penetration base load). As the extent of wind penetration rises, the costs of operating the system increase for at least two reasons. First, the net load duration curve is drawn as if wind power output is known with certainty, but wind output is highly variable, much more so than the variability in supply from traditional generation sources (due to planned and unplanned outages). Greater system reserves are required with wind than without wind. Second, as wind penetrates the system, less of the system load can be met by base-load power plants. There is too much base-load capacity and insufficient peak-load capacity. This will increase the average system-wide power generation costs.

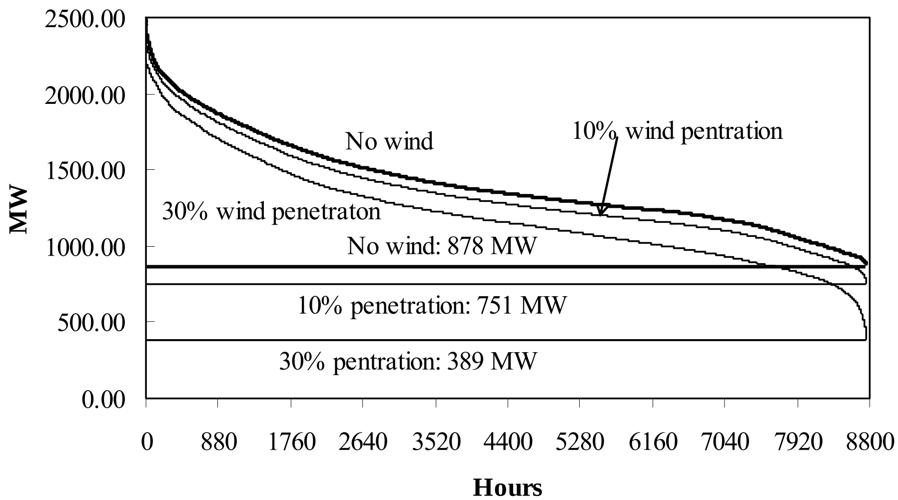


Figure 1: Load Duration Curves and Base Load with No Wind, 10% Wind Penetration, and 30% Wind Penetration

The introduction of wind power into an electricity grid increases the variability of the load to be met by traditional generating sources, making it harder for extant generators to follow the load by ramping up and down. This is shown in Figure 2 where the ERCOT load with no wind is plotted (dark line) for the first two days in January. Also plotted in the figure are the hourly loads that need to be met when wind power enters the grid under 10% and 30% levels of penetration. Even though Figure 2 only covers 48 hours, it is clear that the demand after non-dispatchable wind power has been subtracted has greater variability than the non-wind load, although the adjusted series still track the morning (6 am through noon) and evening (6 pm to 11 pm) peaks quite well. Clearly, and as evident in the figure, a 10% penetration level does not affect net load to the same extent as 30% penetration, although, if a longer profile were chosen, the volatility would be even sharper for both penetration levels. The effect that the variability in net load has on system costs and CO_2 emissions is considered using a simple grid management model (Prescott et al. 2007; Prescott and van Kooten 2009).

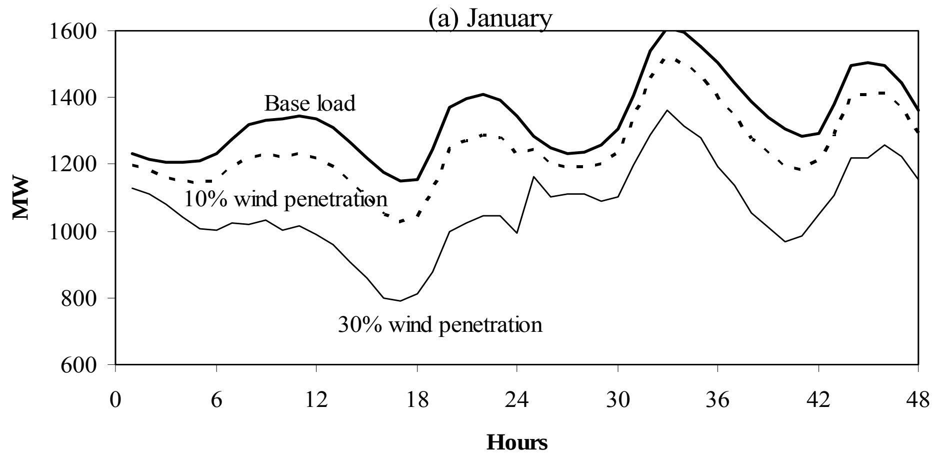


Figure 2: Load to be met by Traditional Generators for First Two Days (48 hours) in January

The costs and benefits of introducing wind power into an electricity grid depend greatly on the characteristics of the electrical operating system, including the pattern of demand and importantly the extant generating mix (including tie-ins to other grids). To illustrate this, we construct an isolated grid model that employs the load and wind data used in Figures 1 and 2. We consider three alternative generating mixes – one that has a large degree of reliance on hydropower (HH), a more typical mix (TT) and a mix that relies mainly on fossil fuels (FF), as indicated in Table 2. These mixes roughly correspond to the generation mixes of Canada, the United States and Alberta. Fuel costs, variable operating and maintenance (O&M) costs and fixed investment costs by generating type are provided in Table 3. Also included in Table 3 are CO_2 emissions per MWh by generating type, although such estimates vary greatly according to the source of fuel, age and type of the technology employed, capacity at which power plants operate, and whether they are based on a life-cycle analysis of power plant operations.

Table 2: Generating Mixes Normalized to 2500 MW Capacity, Three Regions

Technology	High Hydro (HH)	Typical (TT)	Fossil Fuel (FF)
Hydroelectric	1500	210	250
Nuclear	300	500	0
Pulverized coal	450	1250	1250
Combined-cycle natural gas (CCGT)	150	450	850
Open-cycle NG (peak plant)	100	90	150
TOTAL	**2500**	**2500**	**2500**

Table 3 Cost Data for Generating Technologies

Technology	Fuel Cost [$/MWh][a]	Variable O&M [$/MWh][a]	Construction Cost [$ 10^6/MW][b]	Emissions [kg CO_2 per MWh][c]
Hydroelectric	1.13	0.02	1.550	0.009 (0.0284)
Nuclear	6.20	0.07	1.700	0.012 (0.0147)
Pulverized coal	13.70	0.70	1.100	0.980 (1.1340)
Combined-cycle natural gas (CCGT)	37.00	5.00	0.550	0.450 (0.0496)
Open-cycle NG (peak plant)	41.00	4.50	0.460	0.650 (0.0496)
Wind	0	0.17	1.300	0.015 (0.0200)

Notes:
[a] Source: Natural Resources Canada (2005).
[b] Source: IEA (2005)
[c] Source: Summarized from Gagnon et al. (2002), Domenici et al. (2004) and Lightbucket (2008). Natural Resource Canada data are provided in parentheses.

Grid Management Model

The grid management model can be represented mathematically as a constrained optimization (mathematical programming) problem as follows:

$$\underset{Q_{t,i}}{Minimize}\ TC = \underset{Q_{t,i}}{Minimize} \sum_{t=1}^{24\times d}\left[\sum_i \left(OM_i + b_i\right)Q_{t,i}\right] + \sum_r F_r C_r\ , \tag{2}$$

where *TC* is total cost ($); *i* refers to a conventional generation source (*viz.*, natural gas, coal, nuclear, oil, hydro); *r* refers to a renewable source of energy (*viz.*, wind, solar); *d* is the number of days (365 in our model); t is the number of hours; $Q_{t,i}$ is amount of electricity produced by generator i in hour t (MW); OM_i is operating and maintenance cost of generator i (\$/MWh); b_i is the variable cost of producing electricity using generator i (\$/MWh), which is assumed constant for all levels of output; F_r refers to the annualized fixed cost of introducing renewable generation capacity (\$/MW); and C_r is the capacity of new renewable generation type r.[5] In addition, we define D_t to be the demand or load that has to be met in hour t (MW); C_i is the capacity of generating source i (MW); and T_i is the amount of time it takes to ramp up production from plant i. The above objective function is optimized subject to the following constraints:

Demand is met in every period (hour): $$\sum_i Q_{t,i} + \sum_r Q_{t,r} \geq D_t, \forall t = 1,\ldots,24 \times d \tag{3}$$

Ramping-up constraint: $$Q_{t,i} - Q_{(t-1),i} \leq \frac{C_i}{T_i}, \forall i \tag{4}$$

Ramping-down constraint: $$Q_{t,i} - Q_{(t-1),i} \geq -\frac{C_i}{T_i}, \forall i \tag{5}$$

Capacity constraints: $$Q_{t,i} \leq C_i, \forall i \tag{6}$$

Non-negativity: $$Q_{t,i} \geq 0 \tag{7}$$

The model is linear and assumes rational expectations (there is no uncertainty even regarding wind availability), so there is also no need for a safety allowance. These assumptions are for simplicity only (although wind power output can be forecast with a

[5] A carbon tax can be included by adding the following term to objective (2): $\tau \sum_{t=1}^{24\times d}\left[\sum_k \varphi_k Q_{t,k}\right]$, where τ is a carbon tax (\$ per tCO_2) and φ_k is the amount of CO_2 required to produce a MWh of electricity from generation source k (traditional or renewable).

relatively high degree of certainty) and do not in any way jeopardize the main points that we wish to make. Indeed, our conclusions would be all the more poignant if nonlinearities and uncertainty were added (see Maddaloni et al. 2008). We do however add two further constraints: thermal nuclear and coal-fired power plants must be kept running at 50% or more of their capacity to avoid shutting down base plants.

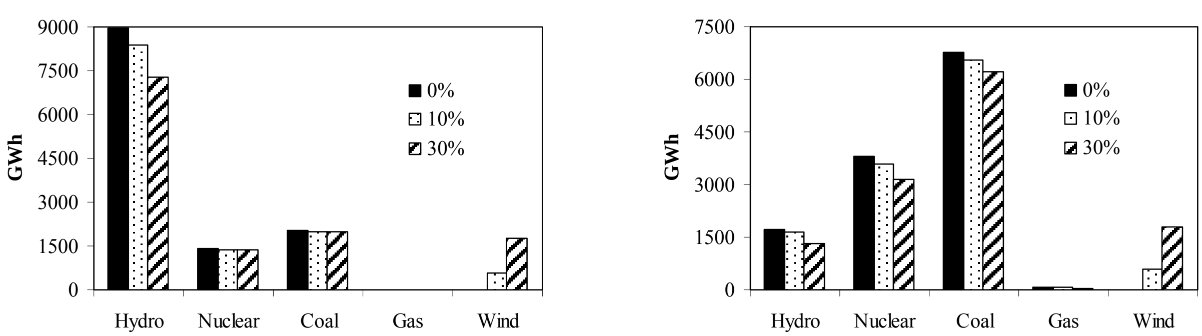
The cost functions represent the ranking of the marginal costs of the five power plants (open-cycle or peak gas > CCGT gas > coal > nuclear > hydroelectric). The ramping constraints are meant to represent a ranking of how fast a power plant adjusts its production. From the fastest to the slowest, the ranking used in this model is hydroelectric = peak gas > CCGT gas > coal > nuclear. The model is solved for 8760 hours representing a full year. Three scenarios are designed based on different wind energy penetration levels: a base case, a low (10% penetration) wind scenario, and a high (30% penetration) wind scenario. The base case assumes that wind energy is not currently used in the energy system with demand satisfied by the existing generating assets, depending on the generation mix that is modeled (HH, TT or FF).

3. MODELING RESULTS

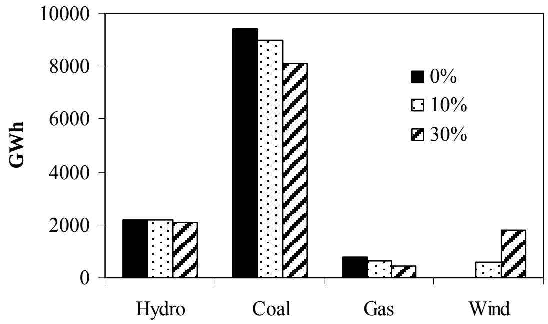
The purpose of the simulation is to indicate potential problems with attempts to integrate wind power into existing networks, and the ease to which this can be done is related to the generation mix. Although our model employs constant marginal generation costs (that vary only with generation type) and simple capacity limits and ramping constraints, the conclusions derived from the simulation results support those of other researchers (DeCarolis and Keith 2006; ESB 2004; Hirst and Hild 2004; Lund 2005;

Nordel's Grid Group 2000; Prescott et al. 2007; Prescott and van Kooten 2009). These are discussed below.

The main electricity output and CO_2 emission results are provided in Table 4. Despite assuming perfect foresight regarding wind availability, generators cannot adapt quickly enough to prevent a rise in unnecessary generation. This is not true in the HH mix as hydroelectric output is able to adjust instantaneously to changes in wind, as indicated in Figure 3(a). Nonetheless, the additional electricity produced in the TT and FF mixes is quite small (at most 1.1% above the no-wind scenario for the TT mix). Not surprisingly, the reduction in CO_2 emissions is also relatively small, and largest for the fossil fuel mix. For 30% wind penetration, the largest reduction in emissions amounts to only 14.5% of no-wind emissions, while emissions are reduced by only 1.3% and 8.1% for the respective HH and TT mixes. Clearly, the degree to which wind power is able to reduce an economy's CO_2 emissions depends on the amount of hydroelectric and nuclear generating capacities there are in the generating mix. If wind displaces non-CO_2 emitting hydro and nuclear power, the fewer will be the emission reduction benefits.



(a) High Hydro (b) Typical



(c) Fossil Fuel

Figure 3: Effect of Wind Penetration on Output of Existing Generators, Various Generation Mixes

The construction cost of a wind power facility (\$1300 per kWh) was annualized using a 10% discount rate and expected duration of 25 years. This constitutes the annual cost of adding wind power to a generating mix. The non-wind power generation costs and total costs are provided in Table 5, as are costs on a per MWh basis and CO_2 emissions. The costs of reducing CO_2 emissions are determined from this information and are provided in Table 6. Notice that system generation costs increase the most for the HH mix and least for the FF mix. Likewise, the costs of reducing CO_2 emissions are highest for the HH mix and lowest for the FF mix, with the latter nearly competitive with other means of reducing CO_2 emissions. The main conclusion is that wind energy should only be considered if the desire is to reduce dependence on fossil fuels for reasons not related to climate change, such as energy security. This conclusion might change for an FF-type mix if prices of coal rise or if one were to construct an electricity grid from the ground up, choosing the optimal configuration of generating plants – an option that might face some isolated and/or developing regions.

Table 4: Electricity Output and CO_2 Emissions by Generating Source for Different Generating Mixes, and 0%, 10% and 30% Levels of Wind Penetration

	Generating Mix					
Scenarios &	High Hydro (HH)		Typical (TT)		Fossil Fuel (FF)	
Generating Facility	Output (GWh)	Emissions (tCO_2)	Output (GWh)	Emissions (tCO_2)	Output (GWh)	Emissions (tCO_2)
No Wind (Base Case)						
Hydro	8940.9	80,468	1722.2	15,500	2189.7	19,708
Nuclear	1412.9	16,955	3810.9	45,731	na	na
Coal	2023.5	1,982,995	6765.0	6,629,740	9414.8	9,226,460
CCGT	5.5	2,493	85.1	38,282	777.7	349,949
Open gas	0.6	397	0.4	281	1.3	816
Wind	na	na	na	na	na	na
Total	**12,383.4**	**2,083,309**	**12,383.7**	**6,729,535**	**12,383.4**	**9,596,932**
10% Wind Penetration						
Hydro	8391.6	75,525	1636.2	14,726	2182.5	19,642
Nuclear	1389.2	16,671	3568.4	42,820	na	na
Coal	2007.3	1,967,115	6535.6	6,404,935	8980.7	8,801,102
CCGT	1.9	877	57.8	26,025	626.7	282,017
Open gas	0	0	0	0	0.2	116
Wind	593.3	8,900	593.3	8,900	593.3	8,900
Total	**12,383.4**	**2,069,088**	**12,391.4**	**6,497,406**	**12,383.4**	**9,111,777**
30% Wind Penetration						
Hydro	7259.8	65,339	1335.0	12,015	2064.8	18,584
Nuclear	1356.4	16,277	3158.1	37,898	na	na
Coal	1987.1	1,947,375	6218.5	6,094,117	8130.6	7,968,006
CCGT	0	0	26.4	11,897	417.1	187,690
Open gas	0	0	0	0	0	0
Wind	1780.0	26,700	1780.0	26,700	1780.0	26,700
Total	**12,383.4**	**2,055,691**	**12,518.1**	**6,182,627**	**12,392.6**	**8,200,980**

Note: na means not applicable

Table 5: Generating Mixes Normalized to 2500 MW Capacity, Electricity Generated, Costs and Emissions

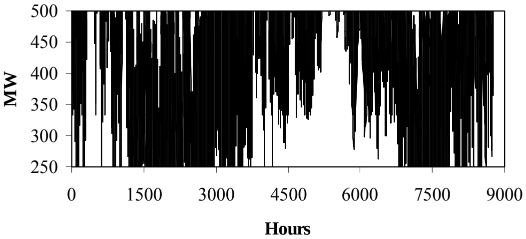
Item	Non-wind electricity generated (GWh)	Non-wind cost ($ mil)	Total cost ($ mil)	Electricity costs ($/MWh)	Emissions (Mt CO_2)
High hydro (HH)					
0%	12,383	53.3292	53.3292	4.31	2.083
10%	11,790	52.0606	87.8653	7.45	2.069
30%	10,603	50.1096	157.5234	14.86	2.056
Typical (TT)					
0%	12,383	142.8803	142.8803	11.54	6.730

10%	11,798	136.0054	171.8101	14.56	6.497
30%	10,738	126.1220	233.5359	21.75	6.183
Fossil Fuel (FF)					
0%	12,383	195.0708	195.0708	15.75	9.597
10%	11,790	180.4431	216.2477	18.34	9.112
30%	10,613	156.0302	263.4440	24.82	8.201

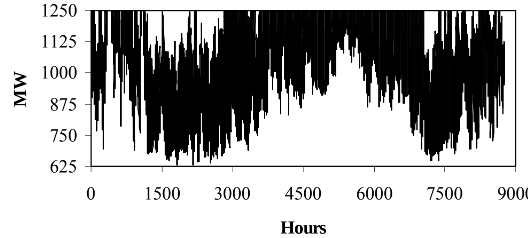
Table 6: Costs of Reducing CO_2 Emissions

Generation mix/	Reducing emissions per tCO_2		Increase in per MWh costs	
Wind penetration	10%	30%	10%	30%
High hydro (HH)	\$2,467	\$3,859	73%	245%
Typical (TT)	\$124	\$166	26%	88%
Fossil Fuel (FF)	\$44	\$49	16%	58%

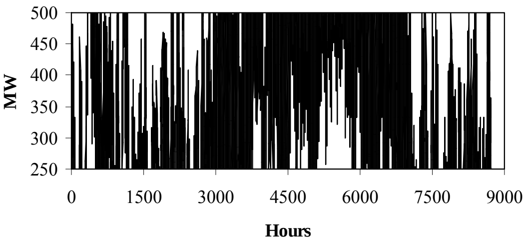
Finally, we consider the impact of intermittent wind on hour-to-hour operations of existing generators. In Figure 4, we compare the impact on base-load nuclear and coal plants in going from no wind to 30% wind penetration. Despite their slow reaction times, nuclear and coal plants do exhibit increased variability in output as wind penetrates the grid (Figure 4). CCGT plants (Figure 5) are also base load but are relied upon to a lesser extent because the model will shift any burden carried by a gas plant towards the coal and nuclear facilities since these need to operate above 50% of capacity. Further, the (constant) marginal cost of operating a gas plant is higher than that of a nuclear, coal or other facility (Table 3). The higher marginal cost explains why peak gas disappears entirely in all mixes when wind penetration reaches 30%, even though greater peaking capacity is generally needed as more intermittent wind enters the system (Prescott and van Kooten 2009).



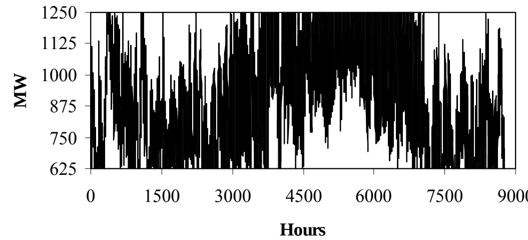
(a) No wind penetration
(Typical mix; nuclear plant)



(c) No wind penetration
(Fossil fuel mix; coal plant)

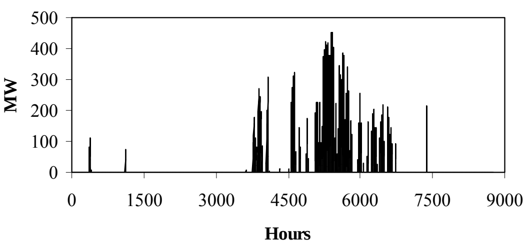


(b) 30% wind penetration
(Typical mix; nuclear plant)

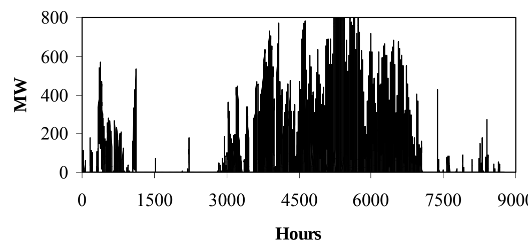


(d) 30% wind penetration
(Fossil fuel mix; coal plant)

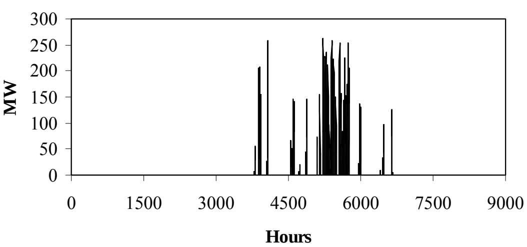
Figure 4: Hourly Adjustment by Base-Load Nuclear Power Plant for Typical Generating Mix (left) and Coal Power Plant for Fossil Fuel Generating Mix (right)



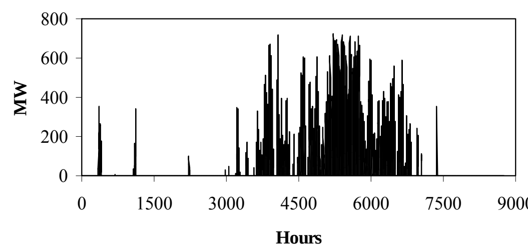
(a) No wind penetration (Typical mix)



(c) No wind penetration (Fossil fuel mix)



(b) 30% wind penetration (Typical mix)



(d) 30% wind penetration (Fossil fuel mix)

Figure 5: Hourly Adjustment by CCGT Power Plant for Traditional and Fossil Fuel Generating Mixes

4. CONCLUDING OBSERVATIONS

The story regarding the integration of wind energy into existing electricity grids is a mixed one. There are undeniable benefits to wind power under certain conditions and in certain circumstances. Conditions depend to a large degree on the location of suitable wind sites and the availability of wind. The best sites are those located on lands where wind turbines least interfere with other land uses, where noise and visual externalities are minimal, and where the effect on wildlife is small. Sites should be scattered over a sufficiently large area so that they are not affected by the same weather patterns. Further, wind sites need to be connected to a transmission grid and, if such a grid does not exist in close proximity, the costs of deploying wind power become exceedingly large. Finally, the degree to which wind can benefit a jurisdiction, particularly in terms of reducing CO_2 emissions, depends on the extant generating mix. Success is most guaranteed when wind power can displace large fossil fuel (primarily coal) generating capacity.

The presence of large-scale nuclear and hydro facilities militates against the use of wind to address climate change as wind power simply displaces hydroelectric and nuclear power, both of which have very low life-cycle greenhouse gas emissions. As our model indicates, the costs of reducing CO_2 emissions are unacceptably large in such cases. A generating mix that might best be suited to greater deployment of wind farms is one that relies principally on fossil fuels yet has enough hydroelectric capacity to enable wind-generated power to be stored in hydro reservoirs. This is an issue that has not been explored here as it requires more detailed information than is currently available.

What many analysts fail to consider in their enthusiasm for wind energy is the impact that wind has on existing base-load and peaking facilities. Results from our grid management model show that extant plants are negatively affected. This is likely the case because the extant mix of generation facilities into which wind power is introduced was nearly optimal to begin with, at least for the circumstances relevant to that jurisdiction. Given that existing electricity grids cannot be changed overnight, it is probably prudent to introduce wind power into a grid at a pace that matches growth in demand and replacement of extant plants. Since electricity grids in many developing countries are not optimal, as seen by power shortages and frequent power outages, there may be greater benefits to the introduction of wind power in developing countries than developed ones.

An alternative policy is to make wind power dispatchable by requiring wind operators to reduce output (by 'feathering' wind turbines or simply stopping blades from rotating) whenever the grid operator is unable to absorb the extra electricity. In this case, output from base-load plants is effectively given precedence over wind generated power because such plants cannot be ramped up and down, the ramping costs are too great, and/or excess power cannot be stored or sold. This policy makes investments in wind farms less attractive, while environmentalists oppose any policies that curtail wind generation as this is considered 'wasteful' of a renewable resource.

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