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All you want to know about the Economics of Wind Power

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All you want to know about the Economics of Wind Power

G. Cornelis van Kooten

Abstract:

Mitigating climate change will require reduced use of fossil fuels to generate electricity. To do so and eschewing nuclear power, countries have turned to wind energy. In this paper, the economics of wind energy are investigated by first examining the social costs and benefits of replacing fossil fuels, with the deciding factor favoring wind based on externalities. The externality costs of fossil fuels relate to adverse health effects of pollutants and the contribution of carbon dioxide emissions to global warming, while the adverse spillovers from wind energy relate to the nature of wind turbines. In general, economic studies find that, when allowance is made for the negative externalities associated with fossil fuel burning, the benefits of wind energy exceed their costs, thereby justifying public intervention. Wind energy is only viable because of generous subsidies, which are shown to be generally effective in bringing about the investments governments desire.

Economic studies that only examine costs and benefits on a macro scale, however, neglect or underestimate the indirect costs of wind energy, which are associated with the impact that intermittent supply has on the operation and management of an electricity grid. To gain a handle on these costs, electricity systems are discussed from generation through transmission and distribution to retail demand. One aspect of this discussion relates to the adequacy of investment in marginal (peak time) generating capacity. In the analysis, it is assumed that the wholesale market for electricity is competitive and that demand responds to changes in spot prices; the implications of these assumptions are also discussed. While most studies are generally optimistic about the potential for integrating wind energy, researchers have identified problems with the inability to store energy (except behind hydroelectric dams), the need for fast-responding backup generating capacity, network instability, low capacity factors for wind power, et cetera, that could limit the usefulness of wind at the high penetration rates now envisioned. Overall, it may turn out that there are economic and physical limits to the proportion of electricity that can be generated by wind and other intermittent energy sources.

Key Words: Electricity; regulated industries; peak load pricing; intermittent energy; storing wind energy; climate change; wholesale spot market for electricity; demand management; fossil fuels and externalities

JEL Categories: H41, L51, L94, Q42, Q48, Q54

1. Introduction

Sustained economic development is generally associated with good governance, which implies low corruption, rule of law, procedural accountability and an effective state (see Landes 1999; Acemoglu and Robinson 2012; Fukuyama 2014). What is sometimes forgotten, however, is that economic growth cannot occur and be sustained without access to cheap and reliable energy; rich countries employ large amounts of energy to create wealth and provide citizens a high standard of material wellbeing (Smil 2003). Economic development in China alone improved the economic wellbeing of so many people that it enabled the United Nations to surpass its Millennium Development Goal of halving the number of people living below the poverty line of $1.25 per day by 2015 (United Nations 2014).[1] The proportion of those living in extreme poverty in China declined from 60% to 12% between 1990 and 2010; to accomplish this, China's energy consumption increased by an average of 6.6% per year over the past two and a half decades, leading to a fourfold increase in energy consumption from 665 million tons of oil equivalent (Mtoe) to more than 3,000 Mtoe.[2] During the same period, energy consumption in India increased more than threefold, or by about 5.1% annually. Poverty and low levels of per capita energy use go hand in hand; thus, to get out of poverty, countries must increase their consumption of low-cost energy by very large amounts. Much of this energy will be sourced from fossil fuels as these are cheap and ubiquitous.

The majority of future growth in energy use will come from developing countries, especially China and India that together account for about one-third of the world's population. Attempts by rich countries to reign in economic growth in poor countries for the purpose of mitigating climate change will be strongly resisted, although rich country subsidies for clean energy and investments in renewable energy will be welcomed by developing nations. Energy policies that lower rates of economic growth in developing countries will simply perpetuate the misery of millions of people who live in poverty, and such policies will be opposed *de facto* if not *de jure*. While clean and renewable energy sources can and do contribute to the energy needs of developing nations, economic growth will depend primarily on traditional sources of energy, such as coal, oil and natural gas, because they are relatively cheap and ubiquitous, and are an enormous improvement over heating with wood biomass, agricultural wastes, dung, et cetera.

Electricity is an increasingly important source of energy in many countries, because it used for

[1] The numbers living in extreme poverty went from 47% of those living in developing countries in 1990 to 22% in 2010, although absolute numbers declined only from 1.9 billion to 1.2 billion (UN 2014, pp.8-9). If China is excluded, the proportion living in extreme poverty went from 41% to 26%.

[2] See *BP Energy Outlook to 2035* and *BP Statistical Review of World Energy* (January 2014), respectively, at http://www.bp.com/energyoutlook and http://www.bp.com/statisticalreview [accessed May 4, 2015]. 1 Mtoe = 11,630,000 megawatt hours (MWh) of electricity.

space heating, cooking, lighting, manufacturing, transportation (e.g., trains, trolleys, trams, subways), and, increasingly, personal mobility with electric and other vehicles.[3] Electricity is also important for powering the digital age – computers and digital storage are reliant solely on electricity. The International Energy Agency (IEA) forecasts that the share of electricity in total energy consumption will increase from 18% in 2012 to 23% in 2040, but technological developments related to hydrogen fuels, computers, renewable energy, et cetera, could well increase the use of electricity to a much greater extent than anticipated; after all, there is a great deal of flexibility in generating electricity from various renewable and clean energy sources (van Kooten 2004, pp.69-72). These sources include solar, tidal, geothermal, wave, biomass, run-of-river and traditional hydro, wastes, wind and even nuclear. The problem with some energy sources is their intermittency, which is best illustrated in the case of wind power.

In this paper, we review the economics of wind power because it has been considered the most important of the available renewable technologies, although solar power now appears to be catching up in this regard (for a review of solar electricity, see Baker et al. 2013). Nonetheless, there continues to be substantial investments in wind generating capacity and the challenges of wind generation carry over to solar, run-of-river hydro, tidal and wave sources of energy. Our focus is primarily on its contribution to mitigating climate change. We begin in the next section with an overview of the electricity generation system and the challenge facing renewables. This is followed in sections 3 and 4 by a discussion of the social costs and benefits of developing wind power. In these sections, the focus is not only on financial costs but also on indirect costs and externality costs (e.g., environmental harms avoided when wind displaces fossil fuel as an energy source; visual disamenities, noise and damage to wildlife from wind turbines).

A more detailed examination of the economics of integrating wind into electricity grids is provided in sections 5 and 6. In section 5, load duration and planning (or screening) curves are introduced and used to answer the question: What is the optimal mix of generating capacities of various fuel types? The impact on the optimal generating mix of carbon taxes versus feed-in tariffs is considered within this framework. Then, the economics of investing in generating assets are examined in the context of deregulation. The main problem is the revenue gap, which occurs because returns to marginal generating assets are insufficient to cover anything but variable costs leaving inadequate returns to incentivize investment in such assets. It is shown that the introduction of wind power could aggravate the revenue gap.

Issues related to the introduction of wind energy into existing electricity systems are discussed in detail in section 6. Although an existing grid has some ability to absorb wind power, as the

[3] Hydrogen (H_2) is considered an energy currency that has the potential to fuel automobiles and even airplanes. Although natural gas (CH_4) is the current source of hydrogen, and there exists potential to derive hydrogen from water (H_2O), electricity is required to separate the hydrogen from both these sources. See Scott (2007) for a detailed discussion of the hydrogen economy.

penetration of wind energy into an electricity system increases, management of the grid becomes increasingly difficult. By 'difficult' is not meant that technical obstacles make the system unreliable. Rather, what is meant here is that the system operator cannot always maintain system stability without curtailing wind output, and legislation might prevent her from doing so. Further, as penetration increases, the reduction in greenhouse gas emissions are increasingly difficult to come by – there is not a one-for-one reduction in CO_2 emissions from existing power plants when wind power enters the system. Both theoretical and empirical aspects are examined.

Policies for incentivizing greater investment in wind energy are considered in section 7. Empirical evidence regarding the success of such policies is examined as are the types of programs available at the national and international levels. Some final observations ensue in section 8.

2. Background

Global Electricity Generation

Global energy consumption by source is provided in Figure 1 for the period 1965 to 2012, with projections to 2035. The International Energy Agency (IEA) expects global energy use to increase by 37% between 2012 and 2040, with electricity demand projected to rise by nearly 80% (2.5% annually) during this period (IEA 2014a, p.201). Electrical generating capacity is forecast to increase from 5,950 GW in 2013 to 10,700 GW by 2040 (2.1% per annum), although gross capacity will need to increase by some 7,200 GW because 2,450 GW of aging plant capacity will need to be replaced, particularly in OECD countries.[4] For example, at the end of 2013, 434 nuclear power plants were in operation with a combined capacity of 392 gigawatts (GW), accounting for 11% of global electricity production (down from a peak of 18% in 1996). Of these plants, some 200 are an older vintage, especially those in OECD countries, and are likely to be decommissioned before 2040. Japan and Germany have explicit policies to reduce or eliminate nuclear power, with both countries having to increase coal generation to compensate (Nicola and Andresen 2012). Meanwhile, the IEA (2014a) projects nuclear capacity in China, India and Russia to increase by 132 GW, 33 GW and 19 GW, respectively, so that, along with expanded capacity in other countries (e.g., Korea), global nuclear generating capacity will increase by nearly 60% to 624 GW.

The share of renewable energy in electricity generation is expected to increase from 21% to 33% by 2040 and account for half of the net increase in new generating capacity over this period;

[4] Kilo is abbreviated with k and equals 10^3; Mega (M, 10^6); Giga (G, 10^9); Tera (T, 10^{12}); Peta (P, 10^{15}). A watt (W) equals 1 joule (J) per second. A kilowatt (kW) equals 10^3 W; megawatt (MW) = 10^6 W; gigawatt (GW) = 10^9 W; terawatt (TW) = 10^{12} W; petawatt (PW) = 10^{15} W; 1 Mtoe = 11,630 gigawatt hours (GWh) of electricity.

currently, hydropower is the largest source of renewable energy, but solar, wind and biomass will be major sources of future increases in renewable generating capacity along with hydro, although environmental lobbying could negatively impact future hydroelectric development.

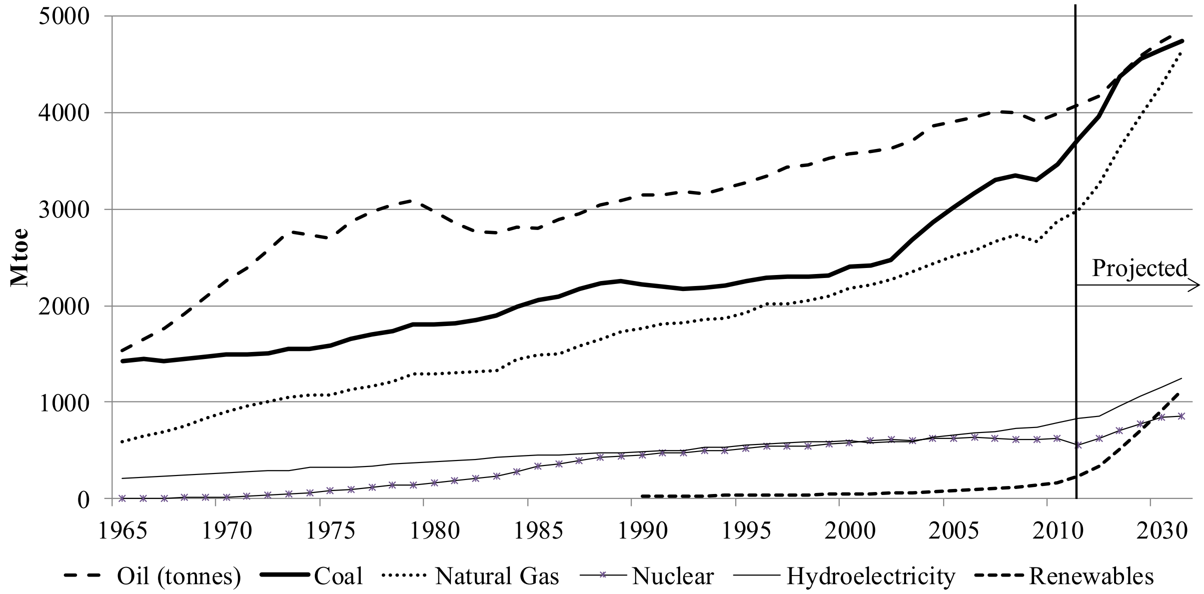

Figure 1: Global Energy Consumption by Source, 1965-2012 and Projection to 2035, Mtoe
Source: *http://www.bp.com/statisticalreview*

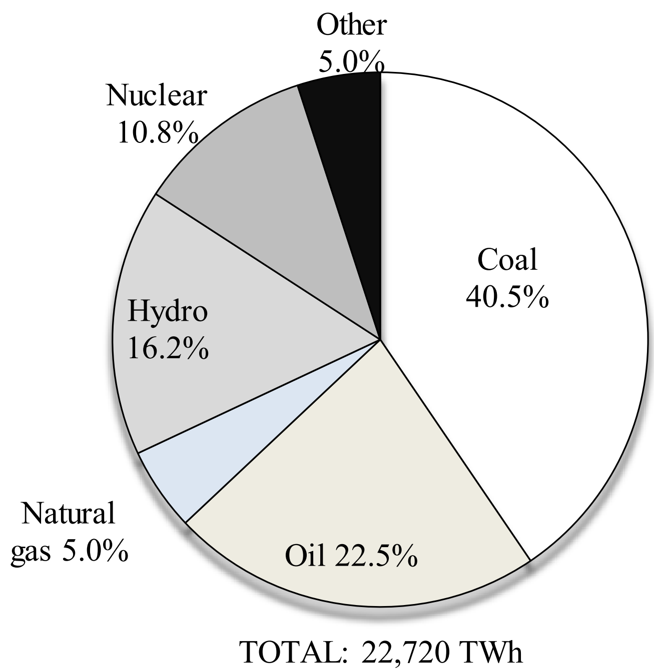

Figure 2: Global Electricity Production by Energy Source, 2012
Source: International Energy Agency (2014, p.208)

Table 1: Primary World Energy Demand by Fuel and Scenario (Mtoe)[a]

Fuel	Current (2012)	Central Scenario 2020	Central Scenario 2040	New Policies 2020	New Policies 2040	450 Scenario 2020	450 Scenario 2040
Coal	3,879	4,457	5,860	4,211	4,448	3,920	2,590
Oil	4,194	4,584	5,337	4,487	4,761	4,363	3,242
Gas	2,844	3,215	4,742	3,182	4,418	3,104	3,462
Nuclear	642	838	1,005	845	1,210	859	1,677
Hydro	316	383	504	392	535	392	597
Bioenergy[b]	1,344	1,551	1,933	1,554	2,002	1,565	2,535
Other renew	142	289	658	308	918	319	1,526
Total	13,361	15,317	20,039	14,978	18,293	14,521	15,629
Fossil fuel share	82%	80%	80%	79%	74%	78%	59%

[a] Under the Central scenario, the growth rate of energy consumption falls from 2% to 1% after 2025; the New Policies scenario assumes that policies proposed or enacted by various countries to reduce CO_2 emissions as of mid-2014 are fully implemented; and the 450 Scenario caps the concentration of CO_2 in the atmosphere at 450 ppmv as required to stabilize the projected temperature increase to 2^{o}C.
[b] Includes traditional and modern uses of biomass for energy.
Source: International Energy Agency (IEA 2014a, p.56)

Currently coal accounts for the majority of power generation, followed by oil (including diesel) and hydraulics (Figure 2). As indicated in Table 1, the IEA (2014a) projects coal use to increase by 50% if no further action is taken to address climate change (Central scenario), while more modest efforts to reduce reliance on fossil fuels (New Policies scenario) will still lead to a 15% increase in coal use. Only if drastic action is taken to prevent the concentration of CO_2 in the atmosphere from rising above 450 parts per million (ppm) does reliance on coal decline by one-third by 2040, although it will still surpass current use in 2020.

If we consider only electricity generation (Table 2), we find that the annual growth in electricity use will surpass two percent in all regions except the OECD countries, with rates of growth in electricity generation below 1% only in Europe and the United States. As a result, the global amount of electricity is projected to expand from 19.6 TWh in 2012 to 34.9 TWh in 2040, or by some 78%, even under a conservative scenario where steps are taken to reduce greenhouse gas emissions.

Table 2: Electricity Generation by Region/Country, 2012, and Projected Generation for 2040 under New Policies Scenario, TWh[a]

Region/Country	2012	2040	Rate of growth
United States	3,818	4,721	0.8%
OECD Europe	3,188	3,881	0.7%
Eastern Europe/Eurasia	1,400	2,086	1.4%
China	4,370	9,560	2.8%
India	869	2,915	4.4%
Africa	620	1,868	4.0%
Latin America	948	1,895	2.5%
Rest of World	2,337	5,921	3.4%
TOTAL	19,562	34,887	2.1%

[a] Excludes power consumption used to generate electricity.
Source: International Energy Agency (IEA 2014a, p.206)

Coal-fired power will dominate electricity production into the foreseeable future unless natural gas prices continue to remain low or even decline relative to those of coal, and/or nuclear energy becomes a politically acceptable alternative. For example, China added 36 GW of coal generating capacity in 2013 and another 39 GW in 2014, and is expected to add the equivalent of an 800-megawatt (MW) coal-fired power plant every ten days for the next decade (Institute for Energy Research 2015). Japan is scheduled to add 43 new coal-fired power plants with a total capacity of 7,200 MW over the next five to seven years to provide reliable electricity output after closing many of its nuclear plants, while India expects to double its electricity production from coal to approximately 2,000 terawatt hours (TWh), or two petawatt hours (PWh) (Business Standard 2015). China and India intend to rely primarily on coal to generate electricity because it is cheap, secure, reliable (providing baseload capacity), and increasingly a clean source of energy (and more so if CO_2 capture and storage can be implemented). Interestingly, the anticipated increase in Indian electricity output sourced from coal more than matches the reduction that the U.S. is seeking to implement.[5] These investments in coal-fired capacity could well be locked in for the next 50 or more years.[6]

As indicated in Table 3, the U.S. and China are by far the largest producers of electricity and the largest producers of coal-fired power. They are followed by a rapidly expanding India, which

[5] The U.S. is hoping to shed 103 GW of coal-fired capacity, which amounts to about 0.77 PWh of output assuming a capacity factor of 85%. The reduction in production from U.S. coal plants in the next decades will be more than offset by the anticipated increase in output from coal plants in India; by 2020, India hopes to produce 1.5 billion tonnes of coal annually (http://www.eia.gov/todayinenergy/detail.cfm?id=22652 [accessed 31 August 2015]).
[6] A coal-fired power plant built in 1919 and operated by Alcoa Power Generating Inc. in North Carolina still generated electricity in 2013 (U.S. Energy Information Administration 2013).

went from being the fifth-largest producer of electricity in 2008 to third place in 2012 while increasing electricity from coal by 36%. Although the U.S. reduced its consumption of electricity from coal by some 33% between 2008 and 2012, it increased production of electricity from gas by 39% during the same period. The U.S. remains the largest producer of electricity from natural gas primarily as a result of shale gas plays, while gas plays an insignificant role in the Chinese and Indian generation mixes. However, China generates the most hydroelectricity of any country, accounting for more than 23% of total global hydropower generation. Canada is third (after Brazil) in the production of hydroelectricity followed by the United States (Table 3), although the latter imported 47 TWh of hydroelectricity from Canada. India is also a major producer of hydroelectricity along with Russia. Yet, hydraulics account for less than 17% of total global generation compared with over 40% from coal and nearly 23% from natural gas. Oil accounts for less than 5% of electricity production, with Japan the largest producer followed by the oil producing states and the U.S. in the top ten countries that employ oil for this purpose.

Table 3: Electricity Generation from Coal, Natural Gas and Hydropower, and Hydroelectric Generating Capacity, Selected Major Countries, 2012

Country	Total Electricity	Electricity from: Coal	Natural Gas	Hydro	Hydro Capacity
	---------- TWh	----------	----------	----------	GW
China	4,985	3,785	[a]	872	194
United States	4,271	1,643	1,265	298	101
India	1,128	801	[a]	126	40
Russian Federation	1,069	169	525	167	49
Japan	1,026	303	397	84	49
Canada	634	[a]	[a]	381	76
Germany	623	287	[a]	[a]	[a]
France	559	[a]	[a]	[a]	25
Brazil	552	[a]	[a]	415	84
Rest of World	7,821	2,180	2,913	1,413	407
TOTAL	**22,668**	**9,168**	**5,100**	**3,756**	**1,025**

[a] Data directly unavailable since the country does not rank in the top ten of producer, and the data are included in the 'Rest of World' category.
Source: International Energy Agency (IEA 2014b)

Two things are clear from this discussion. First, rich countries are rich because they consume large amounts of energy per capita, especially electricity. Second, taken together fossil fuels (coal, oil and natural gas) account for nearly 68% of global electricity generation; when nuclear power and hydroelectricity are taken into account, 95% of electricity is generated by non-renewable, non-hydro sources. The remainder includes geothermal, wind, solar, tidal, wave, biomass and heat, where the latter refers to 'waste' heat that is used to produce power – this is known as combined heat and power (CHP) or cogeneration ('cogen'). While this 'renewable' fuel share has increased from 0.6% in 1973 to approximately 5% today, the share remains small. Clearly, reducing reliance on fossil fuels in a big way presents a tremendous challenge.

Prospects for Wind Energy

One argument used to justify public spending on alternative energy is that the globe will run out of fossil fuels and that we need to prepare for that eventuality. For example, there have long been predictions that the world's oil production will soon scale 'Hubbert's peak' and begin to decline -- that there will be an impending world oil shortage (Deffeyes 2001). Hubbert's peak is predicated on the notion that prices and technology remain unchanged; however, recent developments have shown that the 'peak' shifts outwards with improvements in technology and higher prices. Indeed, from an economic standpoint, the idea that we will run out of oil (or gas or coal) is misguided (Mann 2013). As these resources become increasingly scarcer, supply and demand intersect at increasingly higher prices to ensure that the market clears – so there is always enough of the resource to meet demand. Higher prices, in turn, signal scarcity and thereby induce technological innovations that increase supply, reduce demand and lead to new sources of energy. This is evident from recent advances that have greatly expanded exploitable reserves of oil and natural gas. Indeed, scientists now argue that we might never run out of fossil fuels, especially natural gas (Mann 2013). Therefore, arguments promoting renewable energy should not be based on energy security and/or the potential scarcity of fossil fuels. Rather, the only arguments for reducing or eliminating fossil fuels are related to either prices (renewables are less costly) or to address climate change, or both.

As an alternative to fossil fuels and because nuclear power is considered unsavory, wind energy has become the poster child for the renewable energy sector, although it may now be losing some of its luster. At the end of 2014, the cumulative wind generating capacity installed globally reached nearly 370 GW (Figure 3), with the potential to generate nearly 3,240 TWh of electricity per year (=8760 hrs × 0.37 TW).[7] Based on Table 3, this would then account for some 14% of total electricity production. However, this assumes that the globe's wind turbines would be operating at or near full capacity all the time – that they would generate 370 GW every hour of the year. In practice, a baseload coal plant might operate at a capacity factor (CF) of about 85% (85% of nameplate capacity), while a nuclear power plant operates at a CF of 90-95%, but wind

[7] For details on the latest developments related to global wind generating capacity, see the annual market updates from the Global Wind Energy Council (http://www.gwec.net/publications/global-wind-report-2/ [accessed July 10, 2015]).

farms operate at much lower capacity factors.[8]

Winds are highly variable and wind turbines are unable to produce their maximum nameplate capacity most of the time. Unless the wind blows with sufficient strength, the blades of a turbine will not turn and no electricity is generated, although improvements in blade technology have reduced the threshold wind speed at which energy is produced. Likewise, at high wind speeds, the blades must be turned to avoid wind damage and no output is forthcoming, although technology has increased this threshold as well. Nonetheless, intermittency is unavoidable and thus capacity factors for wind turbines are much lower than for thermal power plants. Hoskins (2015) calculates that, for Europe, the CFs for onshore and offshore wind power averaged 21.2% and 30.0%, respectively, in 2013; for solar, CFs were approximately 11% (see also Darwell 2015). Finally, capacity factors vary across regions. The average CF for wind turbines in the EU is reported to be 22% compared with 33% for the U.S. and only 17% for China; based on 2012 data, wind energy accounted for 4.3% of global electricity production, which implied a CF of approximately 25% (Lacal-Arántegui and Serrano-González 2015, pp.29, 60).

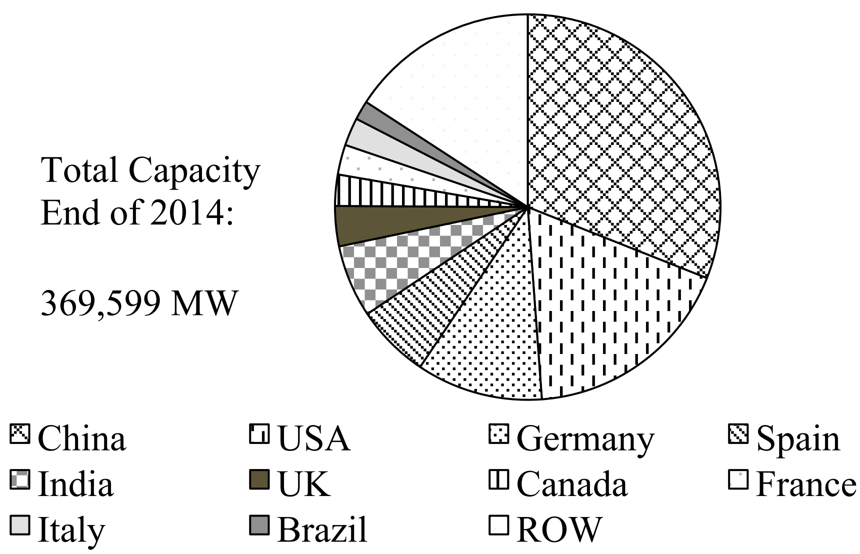

Figure 3: Installed Global Wind Generating Capacity, Top Ten Countries & Rest of World, 2014

Lacal-Arántegui and Serrano-González (2015, p.31) also provide projections of future installed wind generating capacity (with proportion of offshore wind capacity provided in parentheses):

[8] The CF is the ratio of the actual amount of power generated in one year to the potential power that could be generated if the asset operated at full capacity each hour during the year.

Year	European Union	Global
2014	130 GW (7%)	371 GW (3%)
2020	208 GW (13%)	681 GW (6%)
2030	353 GW (32%)	1,391 GW (14%)
2050	503 GW (44%)	2,446 GW (22%)

Assuming a 25% capacity factor, wind would provide 5.4 PWh of electricity in 2050 or some 12% to 15% of global electricity demand. Because fossil fuels are readily available, policies to replace them will likely require a combination of subsidies to producers of clean fuels, regulations forcing firms and individuals to rely more on non-fossil fuel sources, publicly-funded research and development (R&D), contracts to reduce risk, and taxes or cap-and-trade schemes that drive up fossil fuel prices to the point where it makes economic sense for consumers to switch to alternative clean energy sources (Newbery 2011, 2012).

From a practical standpoint there are limits to the amounts governments will pay to subsidize development of non-carbon (clean) sources of energy and to citizens' willingness to accept increases in the price of energy when cheaper fossil fuel alternatives are available. Further, there is the moral question of whether global energy costs should be increased to prevent rises in atmospheric CO_2 when poor people already pay too much for energy, especially in poor countries (Prins et al. 2010). What are the moral implications of policies that prevent or reduce economic growth in developing countries?

Various policies have already been implemented by governments to incentivize investments in renewable energy technologies in the electricity sector. The main ones have been carbon taxes, carbon offset credits (to be sold in mandatory or voluntary carbon market), production and capital investment subsidies, and feed-in tariffs that provide producers with a guaranteed price irrespective of the market price (and whether there is even a buyer). Before implementing policies to incentivize wind energy, however, it is necessary to determine whether the benefits to society of implementing wind energy might exceed the costs. To do so, we need to consider the following:

- What are the costs of developing and operating wind generating facilities and connecting them to the grid? Costs would include not just financial costs but also any externality costs related to visual disamenities, noise, et cetera, and the costs of decommissioning the turbines at the end of their life.
- It is necessary to determine the financial savings from displacing power generated from fossil fuels. This is not an easy task because intermittent wind power imposes indirect costs on the overall system (i.e., on extant generating assets) that depend on the generation mix and can thus only be addressed using a modelling approach.
- Where wind power displaces conventional thermal generation, it is also necessary to

determine the value of the reduced harm when wind displaces conventional generation. The benefits relate to improved human health and, importantly, the better climate impact when fossil fuel use is reduced. The health and climate benefits depend on the extent to which wind displaces fossil fuel generation, which is determined by the wind regime and the existing generation mix; the overall effect can only be determined using an appropriate model. The problem is that the displacement of wind-for-thermal generation is not one-to-one, and it also depends on the social cost of carbon, which is a controversial measure (Pindyck 2015).

If the social benefits of wind power development exceed the social costs, then it makes sense to incentivize wind power. A discussion of the costs and benefits occurs in the next two section sections – in section 3 costs of producing wind power are investigated followed in section 4 by the benefits. Since it is difficult to measure some of the costs to society of renewable energy policies, it is necessary to examine how policies impact the operation of an existing electricity system. Thus, in section 5, we discuss the economics of electricity markets and grids, followed in section 6 by an investigation into how the structure of a grid (generation mix) affects the costs of accommodating wind power into the mix. Policies used to incentivize investments in wind power are discussed further in section 7.

3. Costs of Wind Power Generation

The total cost to society of wind power generation consists of (i) direct costs, (ii) indirect costs, and (iii) externality costs. The direct costs constitute the capital costs plus operating and maintenance (O&M) costs. They include the costs of turbines and related equipment, construction costs, site purchase or rental, site access costs (e.g., road construction and preparation), and construction of connecting transmission lines. Only the costs of connecting transmission lines to the grid are included, but not the costs of the improvements and extensions to the overall transmission system that may be required to accommodate wind (see below). O&M costs are affected by the wind resources at a particular site (primarily mean wind speed and the distribution of wind speed at hub height), which, in turn, determine how much wind power is generated during a year – the capacity factor of the turbines at the site. Indeed, the CF is a key determinant of the cost of harnessing the wind to produce electricity.

The indirect costs are related to the nature of wind power generation and its integration into the power grid. Indirect costs depend on a host of factors, including the pre-existing generating mix, system load profiles, connectivity to grids in other countries/regions, electricity markets, system operating procedures, available storage (e.g., hydroelectric dams), and turbulence effects from one turbine in a wind farm have on another turbine. These factors vary greatly from one location to another, and have a significant impact on the overall costs of wind power generation. If one is interested in the impact of wind energy subsidies on CO_2 emissions, the indirect costs would need to include leakages – the increased CO_2 emissions induced in another region or sector – and additionality – payments made to wind operators for turbines they would have installed even in the absence of such incentives.

Finally, there are the externality or spillover costs related to noise pollution, adverse health effects, loss of visual amenities, impacts on wildlife, risks associated with falling ice, and so on. Like indirect costs, externality costs are location and system dependent. Further, as with indirect costs, the estimation of externalities is associated with a large number of uncertainties and there are no universally accepted methods for estimating them.

Direct Costs

A major challenge for economic analysis of power generation technologies is the variation in cost data across technologies, plant size, countries and time. Since electricity generation technologies vary significantly in terms of their investment requirements and operational characteristics, costs are converted to the same basis for comparison purposes, usually the levelized cost of electricity (LCOE) generation.[9] First, the annualized overnight construction cost (*ACC*) is given as:

$$(1) \qquad ACC = \left(\sum_{i=1}^{K} \frac{OC/K}{(1+r)^i} \right) \frac{r \times (1+r)^T}{(1+r)^T - 1},$$

where OC is the overnight construction cost (\$/MW), or the cost of all material, labor, fuel, et cetera, needed to construct the facility if that cost were incurred at a single point in time;[10] *K* is the time required to build the facility (so it is assumed construction costs are spread evenly over the construction period); *T* is the economic life of the plant; and *r* is the discount rate. Then, the annualized LCOE (\$/MWh) is given by:

$$(2) \qquad LCOE = \frac{ACC + FOMC}{CF \times 8760\,\text{hrs}} + VOMC + F,$$

where *FOMC* refers to the annual fixed operating and maintenance costs that do not depend on

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[9] The levelized costs include capital costs, O&M costs and fuel costs. While capital and fixed O&M costs are proportional to installed capacity, variable O&M and fuel costs are functions of electricity output.

[10] Overnight construction costs ignore interest rates as it is assumed that the generating facility is literally built overnight. While they may not always be a good means for comparing different technologies, such costs are the only ones available. In equation (1), an adjustment is made to account for length of the construction period, although in the analysis that follows the overnight cost is simply taken as given (i.e., *K*=1).

output ($/MW), *CF* is the capacity factor, *VOMC* refers to the variable (output dependent) O&M costs ($/MWh), *F* are fuel costs ($/MWh), and there are 8,760 hours in a year.

A recent study by the U.S. Energy Information Administration (EIA 2013) indicates that overnight construction costs for a 100 MW capacity onshore wind farm would amount to $2,213/kW with annual fixed O&M costs of $39.55/kW; this compares with overnight costs of $6,230/kW and yearly fixed O&M costs of $74.00/kW for an offshore wind farm with a capacity of 400 MW. The EIA (2013) assumes variable O&M costs are effectively zero for wind farms. Assuming a CF of 20% for onshore wind and 30% for offshore wind, and applying a discount rate of 4% and lifetime of 25 years, the levelized costs of onshore wind are $103.43/MWh compared with $179.91/MWh for offshore wind power. Even if the CF for offshore wind is increased to 40%, offshore wind remains more expensive to produce than onshore wind power ($134.93 vs $103.43 per MWh). In contrast, the European Wind Energy Agency (2009) found that wind generated electricity from coastal areas can be up to 36% less costly than power from low-lying onshore wind sites, although this might not be an appropriate comparison because the better onshore wind sites are found at higher elevations.[11]

A more comprehensive analysis of the LCOE is provided in Table 4 for eight technologies – two wind technologies, solar, natural gas, natural gas with carbon capture and storage (CCS), coal, hydro and nuclear. The analysis is most sensitive to the overnight construction cost, so maximum and minimum values are considered in Table 4; an average of the LCOE values is provided in Figure 4. As indicated above, wind power generated offshore is generally more expensive than onshore wind, except when overnight construction costs of onshore wind are at their maximum and those of offshore installations are at their lowest. The lowest costs of generating electricity occur with combined-cycle natural gas plants, followed by hydroelectricity (but not run-of-river) assets, coal plants, and integrated gas plants with CCS (Table 4). The overall average ranking in Figure 4 of different generating technologies clearly indicates that, based solely on capital and operating costs, fossil fuel generation of electricity is clearly the least expensive.

From a policy perspective, the LCOE is meant to provide some indication regarding the potential costs of regulations, subsidies and other measures that shift a generation mix from polluting fossil fuel to clean technologies. Yet, the calculation of the LCOE remains controversial and highly dependent on assumed capacity factors. A more recent evaluation of the U.S. costs of generating electricity, Stacy and Taylor (2015) examine the costs of generating three types of assets: baseload assets capable of dispatching electricity at any time and for very long periods (coal, CC gas, nuclear and hydro), dispatchable peak resources (GT gas) and intermittent resources (wind). They compare EIA estimates of LCOE based on information from existing

[11] In their detailed analysis of offshore wind facilities, Levitt et al. (2011) find that the breakeven prices of wind power often need to exceed $200/MWh to justify their construction.

plants, estimates based on what it would cost to produce electricity from new plants with the latest technology, and estimate for new construction but revised to take into account the observed capacity factors rather than assumed CFs. The results are provided in Table 5.

The results in Table 5 indicate that current costs of producing electricity (LCOE - Existing column) are much lower than those of new construction. This is primarily because the construction costs of many assets have been paid off. Decision makers need to consider this when they implement policies that result in the premature closure of existing generators, because doing so might lead to higher than expected overall electricity costs. Next, estimates of the LCOEs for new construction indicate that, despite recent advances in technology, wind remains at a cost disadvantage relative to fossil fuels, and more so if costs of added transmission and subsidies are taken into account. Finally, if observed CFs are employed to calculate levelized costs, the LCOE for new construction will turn out to be higher than expected by the EIA, thereby reinforcing preference for keeping current assets longer.

Table 4: Cost Information for Analyzing Electricity Production Technologies (US$2008)

Technology		Overnight Construction Cost ($/kW)	Capacity (MW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)[a]	Economic life (years)	CF (%)	LCOE ($/MWh)
Wind (onshore)	Min	1,223	100	28.07	0.00	25	27	33.86
	Max	3,716	100	28.07	0.00	25	23	118.95
Wind (offshore)	Min	3,824	400	53.33	0.00	25	34	83.33
	Max	6,083	400	53.33	0.00	25	37	121.19
Solar PV	Min	2,878	150	16.7	0.00	25	21	100.73
	Max	7,381	7	26.04	0.00	25	21	257.74
Gas CC	Min	538	400	14.62	3.11	30	85	7.40
	Max	2,611	540	14.39	3.43	30	85	23.82
Hydro	Min	757	500	13.44	0.00	80	34	10.82
	Max	3,452	500	13.44	0.00	20	50	58.22
Integrated gas, combined-cycle w. CCS	Min	2,060	340	30.25	6.45	40	85	20.63
	Max	6,268	340	30.25	6.45	40	85	49.19
Supercritical coal	Min	1,958	1300	29.67	4.25	40	85	17.74
	Max	2,844	600	59.23	6.87	40	85	26.57
Nuclear	Min	3,389	2236	88.75	2.04	60	20	89.78
	Max	8,375	2236	88.75	2.04	20	90	81.03

[a] Includes fuel cost.
Source: EIA (http://www.eia.gov/oiaf/beck_plantcosts/index.html [accessed June 4, 2015], Timilsina et al. (2013), and author's calculations.

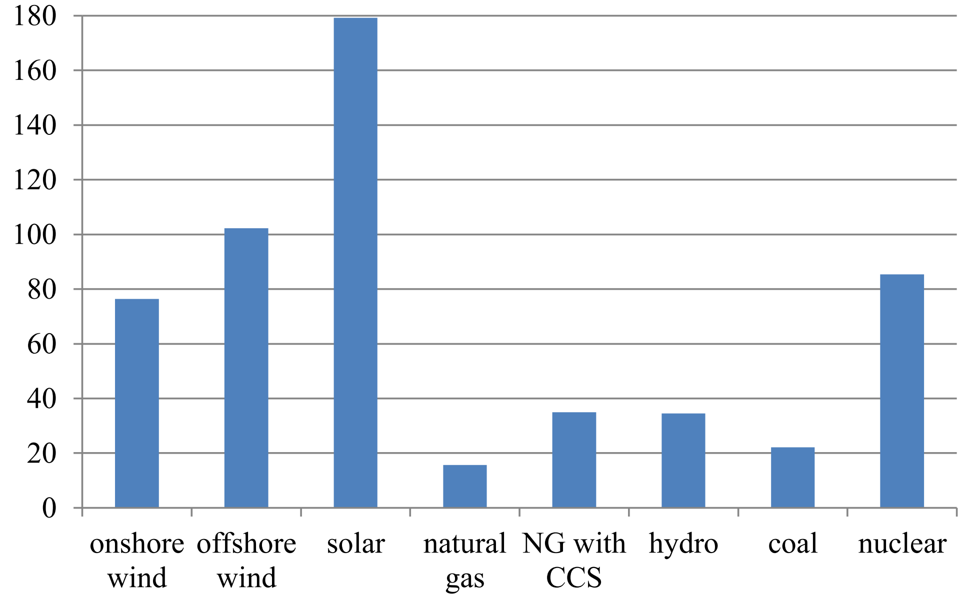

Figure 4: Levelized cost of producing electricity with indicated technologies, US$ per MWh

Table 5: Estimates of the Levelized Costs of Electricity for Existing Plants, New Construction with Optimistic Capacity Factors and New Construction based on Observed Capacity Factors, Three Generating Asset Types

Generator Type	LCOE – Existing (2012 $/MWh)	LCOE – New (optimistic CF) (2012 $/MWh)	LCOE – New (observed CF) (2012 $/MWh)
Dispatchable full-time capable resources (baseload)			
Conventional coal	38.4	80.0	97.7
Conventional combined cycle gas (CC gas)	48.9	66.3	73.4
Nuclear	29.6	96.1	92.7
Hydro (seasonal)	34.2	84.5	116.8
Dispatchable peaking resources			
Conventional combustion turbine (CT gas)	142.8	128.4[a]	362.1[a]
Intermittent resource as used in practice			
Wind including cost imposed on CC gas	Not available	96.2	112.8

[a] To this must be added 'other costs' of $25-$50/MWh related to transmission costs and subsidies not considered by EIA.
Source: Stacy and Taylor (2015)

There are two caveats to consider. First, a comparison of LCOEs across asset types "implicitly assumes that the real marginal value of power will be constant" (Borenstein 2012, p.76).[12] As pointed out in section 6, the use of LCOE to select renewable energy projects (or otherwise make investment choices) can be misleading because the value of power changes over time and space,

[12] Borenstein (2012, p.70) provides a net present value formula for calculating the LCOE.

as does the production of power from various assets, especially intermittent ones. Second, with the exception of nuclear power, where recent cost overruns to address added safety concerns and construction delays led to higher costs, the information in Table 4 excludes externality costs.

Compared to the other clean energy technologies, onshore wind is less expensive on a LCOE basis than solar technologies and integrated gas, combined-cycle gas with CCS, although CCS is still an emerging technology that needs to be deployed at a large scale. As a result, most power plants have only invested in equipment that can capture CO_2 but with no ability yet to store it. It also appears that onshore wind is competitive with run-of-river hydro (indicated in Table 4 by the short economic life of the technology), although offshore wind remains expensive. Overall, available data indicate that traditional fossil fuel technologies are clearly preferred to wind power on a cost basis, unless externality costs are taken into account (as discussed in section 4).

Additional information comes from Lacal-Arántegui and Serrano-González (2015), who provide an excellent overview of wind technology. They determine that the LCOE for onshore wind ranges from €42.9/MWh in the U.S. to €97.0/MWh in Germany (or US$51.5-$116.4/MWh based on the 2012 exchange rate), while the LCOE for onshore wind ranges from €90-€155/MWh, or $108-$186/MWh (pp.51-65). Clearly, the values for onshore wind fall within the range reported in Table 4, but offshore wind costs appear to be higher.

There are three further considerations when it comes to direct costs. First, direct costs of wind assets relative to those of other technologies vary significantly across countries and locations. In some places and situations, wind power is preferred to other clean energy sources, but other clean energy technologies (solar or hydro) may be preferred in other locations. Results cannot be generalized and case-by-case analyses are required.

Second, as noted by Timilsina et al. (2013), studies often ignore transaction costs, which are generally higher for clean energy projects than for traditional ones because of higher technical and financial uncertainties associated with clean energy. For example, it may be more difficult to get commercial loans and banks may charge higher interest rates to account for higher risk. Wind turbines need to be placed across a broad landscape and there are added costs of negotiating rental agreements with landowners, both related to the placement of turbines and the need for additional transmission infrastructure. Since wind farms are generally small, producing much less power than thermal assets and then with greater intermittency, wind power producers have less clout in negotiating favourable terms with larger market players. Clearly, because they are small, clean energy producers face higher transaction costs at every stage of the project development cycle.

Finally, in many countries there is a general lack of economic institutions for facilitating power purchase agreements between wind power developers and system operators (Beck and Martinot

2004). In developing countries, many wind power projects are implemented as turnkey (ready-to-use) projects with bilateral or multilateral funding from developed countries. Once the projects are handed over to a local company or system operator, they encounter constraints related to a lack of operating skills and equipment parts, which eventually leads to increased O&M costs. This is likely a problem for many wind projects financed through Kyoto's Clean Development Mechanism (CDM).

Indirect Costs

Indirect costs refer to the operating costs imposed on the system as a whole when intermittent wind power enters into an electricity grid. Intermittency results in indirect costs related to the need for additional system reserves (e.g., DeCarolis and Keith 2006; Gross et al. 2007), and the extra costs associated with balancing or managing an electricity grid when power from one (or more) generation sources fluctuates to accommodate intermittent wind (e.g., see Prescott and van Kooten 2009; van Kooten 2010; Scorah et al. 2012; Simmons et al. 2015). The underlying reasons for this are discussed in section 5 below. Here the method for calculating such costs is discussed and some estimates of indirect costs are provided.[13]

Suppose that wind can contribute 10% of load at a given time, but that it could potentially contribute nothing to electricity output less than a minute later. If the load is 8,000 MW over this short interval, the intermittent event is equivalent to the loss of a generator with a capacity of 800 MW. Operating procedures require a system operator to have adequate reserves in place to cover the loss of the largest generating unit in the system. If the largest generator in the system has a capacity of 450 MW, then it is necessary to increase reserves by 350 MW to meet the contingent wind event – loss of wind power. The cost of doing this is equal to the direct cost of building such capacity and the variable costs of retaining it in a reserve position. These costs are not inconsequential because payments to keep a generator of only 100 MW-capacity in reserve could run hundreds of thousands of dollars per day. It is also important to notice that, because wind power reduces the wholesale price received by generators (see section 5), there is a greatly reduced incentive to invest in generating capacity.

In addition to the costs of reserves, the system becomes more difficult to manage. There are added wear-and-tear costs due to more frequent ramping up and down of thermal resources, and more frequent stopping and starting of fast-responding, peak-load facilities. In general, fossil-fuel power plants operate below their efficient range, leading not only to higher marginal operating costs but also to greater emissions of CO_2 per MWh. The magnitude of the actual indirect costs incurred will depend on the existing generating mix.

One argument for addressing intermittency and storage relates to the placement of wind farms. If

[13] Stacy and Taylor (2015) include estimates of some of the indirect costs as noted in Table 5.

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 area as possible and integrate their combined output into a large grid. By establishing wind farms across the entire country, onshore and offshore, the United Kingdom, for example, hopes to minimize the problems associated with intermittency. Further, by connecting all countries of Europe and placing wind farms throughout the continent as well as in Britain and Ireland, the hope is to increase the effectiveness of wind generated power.[14] To connect all countries of Europe together, or more generally, all wind farms that are scattered across a landscape, with many sites located offshore and in remote regions, new transmission lines will be required. If the incremental transmission cost is taken into account, the cost of wind power would be much higher than indicated in many studies. For example, Simmons et al. (2015) report that Texas has the greatest wind capacity among U.S. states, with more than 20 GW of installed wind capacity that accounted for 8% of total electricity in 2012. However, to spread wind output over a larger geographic area within the state, the system operator had to increase transmission capacity, which costs individual consumers some $205 annually. The main benefit of the added transmission capacity was a reduction in the number of incidents where wind producers paid utilities to take power. Negative prices were only feasible because wind producers received a subsidy of $23/MWh under the federal government's Renewable Electricity Production Tax Credit (PTC) program (see section 7). Thus, a wind producer would be willing to pay upwards of $23/MWh (or more if there were other subsidies) for the grid to take power.

Unfortunately, increased high-voltage transmission capacity cannot do away with the problem of intermittency – massive transmission capacity does not ensure that sufficient amounts of wind generated power will always be available. Oswald et al. (2008) demonstrated that large weather systems can influence the British Isles and European continent simultaneously. They found that at 18:00 hours on February 2, 2006, electricity demand in the United Kingdom peaked, but wind output was zero; indeed, wind farms added to the load at that time. At the same time, wind output in Germany, Spain and Ireland was extremely low – 4.3%, 2.2% and 10.6% of respective capacities.

Likewise, Miskelly (2012) examined 2010 wind output data for all of eastern Australia – a significant area. They considered an unusually low minimum acceptable output of 2% of installed capacity over 5-minute intervals, finding that the combined power output of all wind farms in the region failed to achieve this minimum standard 109 times, the longest of which was 70 minutes. One typical wind farm failed to achieve at least 2% of capacity 559 times in the six months of the study, with the longest drought in output lasting 2.8 days. Not only does the entire

[14] Geographic dispersion of wind farms in the U.S. is also recommended to insure there is always sufficient wind to mitigate intermittency (DeCarolis and Keith 2006; Kempton et al. 2010).

fleet fail frequently, but it fails at various times throughout the year and not just at predictable times during the year. Miskelly concluded that wind cannot be used as baseload power, and that back-up reserves must be at least 80% of installed wind farm capacity.

In eastern Australia, open- (simple-) cycle combustion turbines (CT) are used for backup; CT gas assets are far less efficient than combined-cycle (CC) gas turbines, but CC gas systems simply cannot ramp quickly enough to track changes in wind power output. Further, CT gas assets must be in constant stand-by mode, wasting energy when the electricity is not needed. It is unlikely, therefore, that even a super grid with many wind farms scattered over a large landscape can avoid the problems and added costs associated with intermittency.

These results suggest that one should not be overly optimistic about the chances that large-scale wind developments will overcome society's need for fossil fuels. Yet, this observation does not imply a death knell for wind. As indicated in Table 6, wind power can reduce CO_2 emissions at reasonable cost for electricity grids with large fossil-fuel generating assets. Further, there are benefits of using wind in developing countries with underdeveloped electricity infrastructure. For example, using wind data from Ethiopia, van Kooten and Wong (2010) found that, because the national grid was unreliable and backup diesel generation expensive, a small community or factory could save millions of dollars per month using wind power. The challenge of integrating wind energy into existing electricity grids depends on so many factors that it is impossible to generalize regarding the indirect costs of wind power. The extant generation mix, the availability of suitable sites for wind farms, the availability of storage (especially behind hydro dams), relative fuel prices, nearby transmission infrastructure, attitudes toward nuclear power, real and perceived externalities of various energy systems, political lobbying, and government policies regarding all of these factors and others (including macroeconomic variables) are some of the considerations that determine the economic feasibility of wind power.

Table 6: Costs of Reducing CO_2 Emissions

	per tCO_2		Increase in per MWh costs	
	Wind penetration			
Generation Mix[a]	10%	30%	10%	30%
High hydro (60-12-18-10)	\$2,467	\$3,859	73%	245%
Typical (8.4-22-50-21.6)	\$124	\$166	26%	88%
Fossil Fuel (10-0-50-40)	\$44	\$49	16%	58%

[a] Values in parentheses refer to the respective percentages of hydro, nuclear, coal and gas capacity in the three extant generating mixes into which wind power penetrates.
Source: Adapted from van Kooten (2010)

Several studies have tried to calculate the full costs of wind power. Simmons et al. (2015) review six such studies to determine the potential direct and indirect costs of onshore wind power in the U.S. Total costs varied from a low of \$59 to \$151 per MWh, well within the LCOE values provided in Table 4. Five of six studies accounted for the costs of subsidies, which ranged from $19 to $23 per MWh. Two included the costs of added transmission ($15 and $27/MWh) and these also included the indirect costs of more frequent ramping of baseload assets ('baseload cycling'), which were calculated at $2 and $19 per MWh. Compared to the capacity factors cited above, those used in the six studies that the authors reviewed were optimistic, ranging from a low of 33% to a high of 41%. The authors concluded that the best estimate of the direct and indirect costs of wind power was about $150/MWh. This did not include externality costs (see below).

Even though comparisons of the full cost of various electricity generation technologies are not available and those comparisons that are made tend to favor traditional generation technologies over renewable ones (e.g., Simmons et al. 2015), many jurisdictions have nonetheless intervened to promote clean energy for generating electricity. Many jurisdictions have subsidized wind, solar and/or biomass power, but until now wind has been the preferred technology on the basis of cost (Figure 4). Policy intervention promoting wind energy needs to be justified on the grounds that the social benefits exceed the costs. The benefits of wind power are discussed in the next section. Before considering these, however, it is necessary to examine the externality costs of wind turbines.

Externality Costs

All energy systems have externality or spillover costs associated with them. Externality costs are not included in Table 4 where only financial costs to an investor are provided; the LCOE calculations also fail to take into account government subsidies and the indirect costs discussed in the previous subsection. With wind turbines, there are significant externality costs related to noise pollution, visual disamenities, health impacts (sleep deprivation from turbines, adverse health effects from transmission lines), dangers from falling ice and broken turbine blades, adverse impacts on wildlife (including endangered raptors), and so on. Some externality costs are likely small because the probability that adverse events occur is small (e.g., falling ice or blades breaking apart), but others might well be significant (visual disamenities, adverse impacts on health and wildlife). While some externalities can be addressed by careful site selection, modifying project design, et cetera (Ledec et al. 2011; McWilliam et al. 2012; Ek and Persson 2014), the needed modifications will undoubtedly increase costs of installing wind generating capacity.

Environmental, land-use and human health impacts are the most widely discussed types of externalities. The most common environmental externalities relate to bird and bat mortality, including those of endangered species, and the loss and fragmentation of natural wildlife habitat.

> "The birds, bats, and natural habitats that may be affected by wind power facilities have significant scientific and sometimes also economic value. Some insectivorous bats are of major (though not fully recognized) economic importance in consuming insects that

> are crop pests or nuisance species such as mosquitoes. In addition, some of the birds that are prone to collisions with wind turbines—such as eagles, storks, and other migratory species—are highly charismatic and of special interest for wildlife viewing; areas where these species are concentrated may be important from an eco-tourism standpoint. Finally, some of the windy sites that appear attractive for wind power development are also of considerable biological interest because of concentrations of migratory birds, other wildlife, or rare plants such as on mountain ridge-tops in the tropics" (Ledec et al. 2011, p.14).

One study of bird kills at Altamont Pass wind farm in California by Thelander et al. (2003) found 226 raptors and 213 other birds had been killed over a period of one year as a result of the rotating blades on wind turbines.[15] Among raptors, 103 red-tailed hawks, 51 burrowing owls, 26 barn owls, and 11 golden eagles had been killed; pigeons were the most common fatality among other birds. The authors concluded that each turbine was responsible for the death of 0.2 birds annually. Other researchers report a much higher mortality rate for the same wind farm of 8.14 birds annually per MW of installed capacity (see Kempton et al. 2005, p.133). In their analysis of the proposed wind farm off Cape Cod, Kempton et al. (2005) assume that the installation of 130 turbines would lead to 364 to 3,516 deaths per year, or a rate of 2.8 to 27.0 birds per turbine – a death rate much higher than that reported by Thelander et al. (2003).

In a review of 73 studies that estimated bird deaths from wind turbine encounters, Loss et al. (2013) report mortality rates of 20,000 to 573,000 annually for the contiguous U.S. Assuming an installed capacity of approximately 54 GW for the U.S., the annual mortality rate is somewhere between 0.37 and 10.61 birds per MW of installed wind capacity. Based on a meta-regression analysis, Loss et al. (2013) determined annual mortality by region: California, 18.76 birds per MW of installed capacity (7.85 birds/turbine); U.S. East, 3.86 birds/MW (6.86 birds/turbine); U.S. West, 2.83 birds/MW (4.72 birds/turbine); and U.S. Great Plains, 1.81 birds/MW (2.92 birds/turbine). They also found that mortality, especially of raptors, increased when newer, more technically advanced turbines were installed (see Lacal-Arántegui and Serrano-González 2015).

Bat mortality exceeds that of birds by a factor of two to four. Based on data from 21 studies of 19 different wind farms from five regions in North America, Ledec et al. (2011, p.24) found annual mortality ranged from 0.9 to 53.3 bats per MW of installed capacity, with a mean of 12.8 bats/MW. The authors also report an annual mortality estimate by Erickson et al. (2005) of 3.04 birds/MW for U.S. wind farms. These numbers are lower than those reported for Germany and

[15] The Department of the Interior had created a regulation allowing wind energy companies to obtain 30-year permits to kill protected Bald and Golden Eagles without prosecution by the federal government. However, the U.S. Northern District Court of California ruled in San Jose (August 12, 2015) that it violated federal laws. https://www.masterresource.org/cuisinarts-of-the-air/bald-golden-eagles-court-victory/ [accessed August 17, 2015]

France where monitoring is more intensive.

Birds and bats provide important ecosystem services because they consume mosquitoes and other insect pests and, in the case of raptors, keep populations of rodents in check. Birds also provide visual and other amenities that people value. Assume that, at the margin, the former services that birds and bats provide are valued annually at $1/bat and $1/bird, but that common birds also provide other amenity values worth $1/bird. In the case of raptors, however, individual birds are valued between $15 and $30. Using the U.S. average bat mortality and assuming one-half of bird mortality constitutes raptors, it is possible to estimate the annual externality costs due to bird and bat mortality from wind turbines: in California, $172-$313/MW; U.S. East, $46-$75/MW; U.S. West, $37-$58/MW; and U.S. Great Plains, $28-$42/MW. While these values appear rather large, their contribution to overall electricity costs is actually small. Assuming a 100 MW wind farm and capacity factor of 25% (see Table 4), bird and bat mortality would add between 1.3¢ and 14.3¢ per MWh to the costs of electricity, depending on the region.

Ledec et al. (2011) argue that wildlife habitat externalities can be addressed by landscape, vegetation and public-access management methods, and the use of conservation offsets or compensatory mitigation (pp.53-57, 95-100), but they cannot be fully mitigated. While no data are available concerning the potential costs of such strategies, it is obvious that they will vary from one location to another. Bird and bat mortality can be reduced by raising the cut-in speed when turbines begin to generate electricity (bats) and shutting down wind generation for short periods during peak migration (birds) (pp.48-52). The costs in these cases are measured by the reduced output of electricity, and again will vary by location.

Studies have also considered health and nuisance impacts from wind turbines. These include shadow flicker (which has negative impacts, for example, on those with Meniere's disease), noise pollution, visual disamenities, and safety concerns (e.g., falling ice, interference with communications, aircraft dangers). Scientists are only beginning to investigate the noise and other potential health impacts of wind turbines (e.g., Australian Acoustical Society 2012; Cooper 2012; Miskelly 2013).[16] While annoyance is currently considered the most important issue associated with noise, and thus downplayed, the long-term health effects of living near wind turbines remain unknown. The only evidence currently available is the fact that, in Ontario, people have sold or abandoned their homes when turbines were built too close.[17] In the Ontario

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[16] See also papers presented at 'Inter-Noise 2014: 43rd International Congress on Noise Control Engineering' held in Melbourne, Australia, 16-19 November 2014 (https://www.wind-watch.org/documents/wind-turbine-noise-papers-from-inter-noise-2014-conference/ [accessed July 9, 2015]).

[17] This is a claim made in *Big Wind*, a documentary film by A.J. Neidik (DLI Productions and Productions Grand Nord, 2014) available from http://www.dliproductions.ca/films/big-wind/ [accessed July 9, 2015].

case, legislators would not accept 'not-in-my-backyard' (NIMBY) considerations as a sufficient reason to permit energy companies from placing large wind turbines near rural residences. Although little is known about how noise effects on rural residents dissipate with distance, with some jurisdictions requiring wind turbines to be placed no closer than 1,500 to 2,000 m from residences, this could add to costs. Noise and other issues related to location also intertwine with other externalities that economists have studied.

If we consider visual aspects, the nonmarket costs might well be sufficiently large to disqualify some potential wind sites. Estimates of the visual disamenities associated with wind turbines can best be estimated using contingent valuation or other stated preference methods (Freeman 2003). The problem is that, if compensation demanded is used as the criterion for calculating the visual or noise disamenity, the external costs of wind power will be significantly higher than if willingness to pay is used. Economic reasoning would suggest that, the nearer a potential wind farm is to a large urban centre, the greater will be the external cost, but locating wind turbines in more remote locations generally increases transmission costs. What have empirical studies shown?

Ladenburg and Dubgaard (2007) employed a choice experiment to determine the willingness to pay (WTP) for reducing the visual disamenity associated with offshore wind farms in Denmark. Compared to locating a wind farm of 720 turbines (3600 MW capacity) eight km offshore, survey respondents were willing to pay an average of €46 per year to relocate them to 12 km from shore, €96/year to locate them 18 km from shore and €122/year to locate them 50 km off shore. This translates into a value of €11/km per year at 8-12 km from shore, declining to €1/km at 50 km. Overall, Danish households were willing to pay between €33 and €107 annually to move wind farms farther off shore, although those households with a residence or summer home where they could look out over the ocean would be WTP between €280 and €468 annually.

Similar results were found by Krueger et al. (2011), who also used a choice experiment to determine the disamenity values of locating wind farms off the coast of Delaware. They examined the compensation required to locate wind farms at distances of 0.9 miles (1.4 km), 3.6 mi (5.8 km), 6 mi (9.6 km) and 9 mi (14.4 km) from shore. The median compensation demanded per household declined with distance: $19 (2006 US$) at 0.9 miles, $9 (3.6 mi), $1 (6 mi) and $0 (9 mi), but only for inland residents. For those living near the ocean, compensation demanded averaged $0, $69, $35 and $27, respectively. The aggregated compensation required would add $7.6 million, $4.2 million, $1.1 million or $0.9 million annually to the cost of the wind farm, with lower costs associated with the greater distance. However, as distance from shore increases, so does the cost of transmission. Interestingly, attitude surveys by Firestone et al. (2009) found that 78% of Delaware residents would support the development of a wind farm six miles (9.6 km) from shore, but only 25% of Cape Cod, Massachusetts residents would be willing to do so. However, the surveys differed in terms of the targeted population (all-state vs specific region) and hypothetical versus actual development possibilities.

A survey of residents in a North Carolina county found that, while 35.8% of respondents were willing to participate in green energy programs, households demanded a median compensation of $23 per year to permit a proposed wind farm in their county. This would add some $426,400 (or $95,200-$724,900) annually to the cost of the wind project. Finally, in a review of contingent valuation studies, Ladenburg (2008) found that people were willing to pay significantly more to locate wind farms offshore rather than onshore (see also Firestone et al. 2009, 2012).

More recent studies considered the effect of wind farms on property values using hedonic pricing methods. In an UK study, Sims et al. (2008) examined 201 house sales within one mile (1.6 km) of a 16-turbine wind facility. They could not find any statistically significant adverse effect from visual disamenities, but they did find some evidence that noise and flicker had negative effects on property values. The authors also reported that a study of 1,810 properties located within 20 km of a Scottish wind farm found house prices had declined by 7%.

Heintzelman and Tuttle (2012) examined a total of 11,331 properties in three counties in northern New York State using several types of models. For two of the three counties and all models employed in the analysis, property values declined as a result of nearby wind turbines; in the third county, results were mixed with some models suggesting no impact on property value. Using their baseline model, the authors found that the values of homes located within a half mile (800 m) of the nearest wind turbine declined by 8.8 to 15.8 percent, or between $10,793 and $19,048. For other models and depending on the county, property values fell by as much as 26%-35%. The impact on property values fell with distance from the nearest turbine, so that at 3 miles (4.8 km) distance, property values declined by only 2%-8% ($2,500-$9,800).

Not all hedonic price studies identified an unambiguous decline in property values. For example, Hoen et al. (2011) surveyed 7,500 properties located near 24 wind facilities in the U.S., but they could find no statistically significant decline in property values. However, the sample was dominated by rural, low-valued properties, none of which were within 800 feet (about 250 m) of the nearest turbine. Likewise, Vyn and McCullough (2014) found no adverse effect of wind turbines in Ontario. However, they examined only a small sample of rural farms, many of which were located a substantial distance from the nearest turbine (see Skaburskis 2015).

Finally, Wang and Prinn (2010) found that, if one-tenth or more of the globe's energy is eventually to come from wind, the wind turbines themselves could cause surface warming exceeding 1°C, and alter clouds and precipitation well beyond the regions where turbines are located. The need for wind turbines on such a massive scale would also exacerbate the undesired environmental and human health impacts, thereby causing policymakers to rethink this option and consider ones that produce fewer negative externalities, such as nuclear power.

When we attempt to make sense of the forgoing values, we find that the externality costs associated with wind farms could add little to the overall levelized cost of electricity. For example, we calculated that bird and bat mortality added 1.3¢-14.3¢ per MWh to the LCOE. Assuming visual disamenity costs of \$0.9-\$7.6 million for an offshore wind farm in Delaware, 400-MW capacity and a 35% capacity factor, the added cost would amount to \$0.73-\$6.20/MWh. A similar calculation for onshore wind in North Carolina (\$95,000-\$725,000 externality cost, 100-MW capacity wind farm, 25% CF) gives externality costs of \$0.43-\$3.31/MWh. Taking the upper values of wildlife damage and visual disamenity values, and then doubling these to account for health and other potential externality costs, leads to externality costs of \$12.69/MWh for offshore wind and \$6.91/MWh for onshore wind. For comparison, Simmons et al. (2015, p.32) report externality costs of \$9/MWh for onshore wind, which includes costs of CO_2 emissions associated with the construction of wind turbines.[18] Finally, assuming the lowest LCOE values in Table 4 for offshore and onshore wind farms, externality costs would increase the costs of wind by 15% (offshore) to 20% (onshore). Externality costs could be significant in some cases, but they could also be easily mitigated at low cost by optimal site selection algorithms (e.g., McWilliam et al. 2012). Although not considered here (but see below), the externality costs of wind farms are likely smaller than those of thermal power plants.[19]

In summary, despite the efforts that have gone into measuring the externality impacts of producing electricity from wind, little is known about the magnitude of the externality costs. The calculations in the preceding paragraph are only one effort to suggest some bounds as to the possible size of the spillover costs. While economists have focused on visual disamenity values and the impact of wind turbines on property values, the conclusions from such economic studies have been mixed. It is likely that the externality effects captured by land values might only be a small proportion of the total externality impact, although more research is required to determine if this is indeed the case. Further research is also needed to determine the importance and extent to which externality costs contribute to the overall cost of deploying wind power technologies.

4. Benefits of Wind Power Generation

The benefits of wind generated electricity consist of three types. The direct benefits are the savings realized when less electricity is generated by assets displaced by wind. For example, there is a reduction in coal consumption when wind power replaces electricity generated from coal, and these savings could be substantial. Next, there are indirect benefits that could be

[18] Many onshore wind towers are now more than 100 m high at hub height with a rotor diameter exceeding 150 m. While blades are made of fiberglass or carbon-glass composites, towers are built of concrete and steel; the construction of wind turbines emits great deal of CO_2.
[19] Simmons et al. (2015) report externality costs of \$53/MWh for coal.

nonmarket in nature. For example, a coal-fired power plant might shut down resulting in the eventual reallocation of land uses that benefit nearby residents, or residents might simply find a landscape that includes wind turbines to be visually appealing. Finally, a major source of benefits relates to the damages that are avoided when clean wind power substitutes for electricity generated from fossil fuels. These types of benefits are considered in this section.

Direct Benefits from Wind Power

If a wind farm with a generating capacity of 100 MW is developed and, importantly, integrated into an existing grid, then any wind power that enters the grid will replace power generated by other assets. The savings realized by the other generating sources are a benefit attributable to the wind farm. Assuming that the wind farm has a capacity factor of 25%, it will on average produce 219.0 GWh of electricity annually. Suppose the generation mix consists of coal and natural gas, and that wind power replaces, in equal amounts, electricity generated by coal and natural gas. Using averaged levelized cost of electricity data from Table 4 for coal ($22.16/MWh) and natural gas ($15.61/MWh), the annual savings would equal $4.136 million. Based on the LCOE for onshore wind ($76.41/MWh), the cost of producing the wind power is $16.733 million. Thus, the annual cost deficit would only be $12.597 million rather than the higher value. This cost would then have to be covered by other benefits.

Unfortunately, the forgoing type of analysis might be overly optimistic for two reasons. First, although technical advancements will continue to lower the costs of wind through increased efficiency gains in turbine technology and the siting of wind farms (McWilliam et al. 2012; Ek et al. 2013). But innovations also reduce the costs of other technologies, perhaps to an even greater extent in some cases (e.g., fracking has significantly reduced the price of natural gas).

Second, the above analysis assumes that, on average, a MWh of electricity replaces 0.5 MWh of coal and 0.5 MWh from gas. Due to its intermittency, however, the extent to which wind power substitutes for electricity generated by other assets depends of the time of day and the assets generating power at the time. When demand for electricity is low and met solely from coal, one MWh of wind-generated power will displace a MWh of coal; during times of peak demand, a MWh of wind energy will displace a MWh of GT gas. For example, Cullen (2013) investigated the impact of wind energy using an econometric model and data for 2005-2007 from the Electricity Reliability Council of Texas (ERCOT). Data consisted of wind output and power production from 332 individual generators 15-minute intervals. Cullen (2013) found that, on average, one MWh of wind replaced 0.85 MWh of gas and only 0.18 MWh of coal generated power, despite the fact that coal accounted for about 40% of production.[20] However, if ramping rates were taken into account (via a dynamic econometric model), one MWh of wind displaced 0.92 MWh of gas-generated electricity and a negligible amount of coal. Similarly but using

[20] Values do not sum to 1.0 because of imports or exports.

hourly ERCOT data for the period 2007-2011, Novan (2015) found that wind displaced coal during periods at night when demand was low, while it displaced gas when demand was higher.

Using an operations research approach to investigate the impact of wind on an existing grid, van Kooten (2010, 2012b) also concludes that wind will displace peak gas before it will displace coal. However, because he permits some storage of wind-generated power during periods of low demand, thereby avoiding ramping costs associated with baseload coal, wind power will have a greater tendency to reduce output from gas plants before coal output is reduced.

The reason why studies by van Kooten (2012b), Cullen (2013) and Novan (2015) find a higher elasticity of substitution between wind and gas than between wind and coal relates to the responsiveness of CT gas. If wind power fluctuates when the marginal asset is an open-cycle gas turbine (as during peak demand periods), variable wind output can easily be accommodated by simply applying more or less pressure to the 'gas pedal' – the elasticity of substitution or ramp rate is essentially infinite. Even so, if the gas turbine is required to go into idle mode or shut off entirely, the additional costs related to the burning of fuel while generating no electricity in idle mode, or the added wear and tear on gas turbines because of more frequent 'cold' starts, get ignored. If all of the CT gas is off line, the marginal asset will be a CC gas plant, and not a coal plant (as discussed in section 5). Finally, if all gas plants are off line, which occurs at lowest demand levels, the marginal asset will be coal. Hence, wind will rarely displace coal, unless a tax is levied on CO_2 emissions (van Kooten 2012b; van Kooten et al. 2013).

If wind replaces power from baseload facilities, such as coal or CC gas plants, the costs are much higher because the elasticity of substitution between wind and coal energy is not infinite as coal plants cannot ramp up and down sufficiently fast enough to track changes in wind output. (A CC gas plant has greater ability to adjust output than a coal plant simply because of the nature of the fuel source). If too much electricity is generated, the system operator must curtail wind power (by turning the turbine blades parallel to the wind direction) and/or immediately reduce the pressure in the boiler of the coal/CC gas plant to reduce power output. There is a cost to both options. Artificially reducing wind output not only results in the loss of renewable energy but it also reduces incentives to invest in wind energy. As a result, most systems treat wind as 'must run' or non-dispatchable – any wind power that is generated must be permitted into the system. However, it could be more costly to reduce power from the baseload plant – the release of steam (pressure) constitutes a waste of energy, but it also stresses equipment while immediately increasing the per unit cost of generating electricity as the plant is no longer operating at optimal capacity. This also results in higher per unit CO_2 emissions. Further, since the baseload plant is now operating at lower capacity, it cannot ramp fast enough to respond to a subsequent fall in wind output. As a result, fast-responding backup power in the form of natural gas or diesel generation is required.

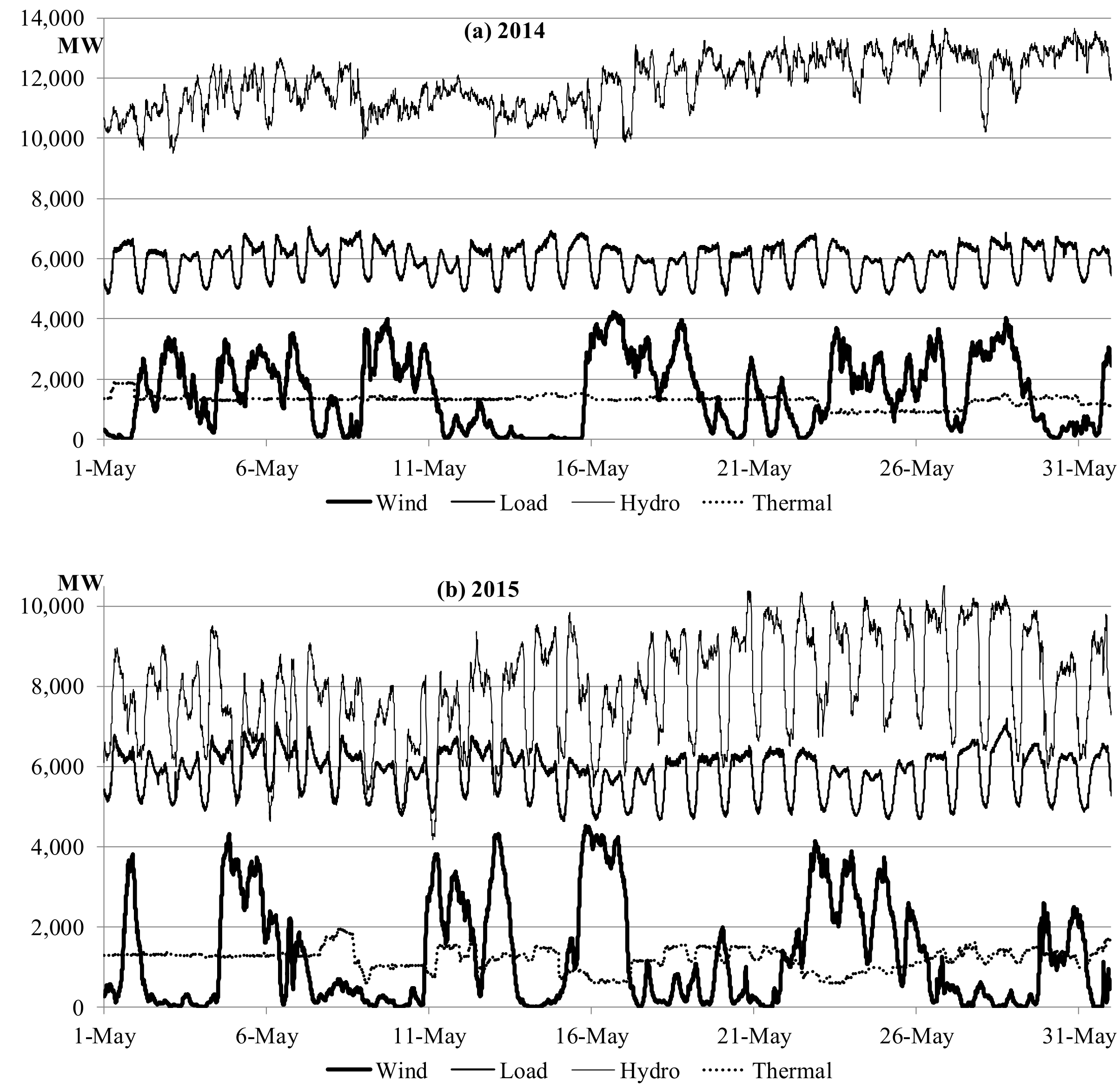

Figure 5: Conflict between Wind and Hydro Power Generation in the Pacific Northwest, May 2014 and May 2015 (Source: http://transmission.bpa.gov/business/operations/Wind/baltwg.aspx)

Finally, there are situations where non-dispatchable wind power simply replaces hydroelectricity, so that one form of clean energy substitutes for another. Although wind power can be stored behind power dams, so that wind and hydraulic energy complement each other (see section 5), they could also be in conflict as appears to be the case in the U.S. Pacific Northwest (PNW).[21] In Figure 5, load and wind, hydro and thermal outputs are plotted in 5-minute intervals for May 2014 and May 2015. Wind generated electricity totalled 1,159 GWh in May, 2014 compared to

[21] The discussion here is based on Holman (2008), de Marsella (2011) and Conca (2014). The conflict is evident in Figure 5, particularly for 2015.

only 940 GWh in May, 2015; likewise, hydro production in May, 2014 exceeded that in May, 2015 – 8,816 GWh versus 5,889 GWh. This is also clear from Figure 5 once one considers the differing scales on the vertical axes. Nonetheless, both graphs indicate that hydroelectric output tracks not only the twice-daily peaks and valleys in load, but also changes in wind output. This is most evident in the 2015 data where hydropower fluctuates widely in response to wind; indeed, even thermal power plants attempt to follow changes in wind output. It is clear that the presence of large wind farms destabilizes the Pacific Northwest's power grid.

Part of the reason for conflict arises due to lack of high-voltage transmission interties with other regions, or insufficient storage in the system. If too much wind is generated at any given time, water in the Columbia River must be spilled rather than allowed to run through the turbines and generate electricity. This constitutes an opportunity cost to be charged to wind. However, if too much water is spilled, migrating salmon can be harmed. Thus, if there is too much water in the system, the Bonneville Power Authority (BPA) must necessarily curtail wind power to avoid damage to migrating fish. This results in lower capacity factors for wind, which increases costs.

Indirect Benefits of Wind

The indirect benefits of wind power are limited, but there are some indirect benefits that one might want to consider. For example, many commentators identify energy security as a major benefit of wind power and renewable energy more broadly. Greater reliance on renewable sources for generating electricity leads to a reduction in imports of fossil fuels. This is true for China, India, Japan, Europe and many other countries, but it is likely not the case for the United States where this argument has gained the most traction. Unlike China, India, Japan and Germany, the U.S. does not need to import fossil fuels for electricity generation as it has sufficient coal and natural gas. In contrast, Germany relies on imported natural gas from Russia, although it sources much of its own coal (including lignite which has a high CO_2-emissions intensity).

Some indirect benefits might more appropriately be considered positive externalities. Surveys indicate that individuals might be willing to pay more for green energy (Groothuis et al. 2008), with some expressing a positive attitude towards wind turbines because of their visual and other amenity values (Sims et al. 2008, p.253). For example, Borchers et al. (2007) show that customers in New Castle County, Delaware exhibit a marginal willingness to pay (WTP) of 1.3 cents per kWh for wind energy because they gain more utility from wind energy as compared to fossil fuel based generation. Another indirect benefit attributed to offshore and not necessarily onshore facilities pertains to habitat creation, with Wilson and Elliott (2009) arguing that offshore wind structures lead to a net increase in habitat for aquatic life.

Because energy security and other values are inadequately reflected in energy markets, governments have responded positively by providing various incentives to generate more power from wind turbines. However, there has been little effort to quantify these types of benefits and, compared to other benefits of wind energy, they are likely insignificant, although future research might suggest otherwise.

Environmental Damages Avoided

Owen (2004), and Roth and Ambs (2004), argue that wind power could compete with fossil fuels if environmental externalities from fossil fuels are appropriately accounted for in calculating true social costs. The International Energy Agency estimates that subsidies to fossil fuel consumption amounted to $548 billion in 2013 (IEA 2014a, p.314). But a recent study by the International Monetary Fund (IMF) finds that, if environmental damages of fossil fuel use are included as a subsidy to fossil fuels, subsidies are nearly nine times higher, or some $4,858 billion (Coady et al. 2015). While direct pre-tax subsidies to coal are small, the IMF study concludes that, once externalities relating to the adverse impact on health and climate change from burning fossil fuels is taken into account, subsidies to coal tallied $2.5 trillion in 2013 while subsidies to petroleum, natural gas and electricity summed to $1.6 trillion, $0.5 trillion and $0.2 trillion, respectively (see Table 7). Overall, total subsidies to fossil fuel consumption were an incredible 6.4% of global GDP in 2013.[22] Externalities alone cost $4.310 trillion, or 5.7% of global GDP.

A major source of pollution from fossil fuel burning is local, so that estimates of environmental damages would differ across air sheds. In a study of Ontario's feed-in tariffs (FIT) for green energy, Dewees (2013) calculates the harm from non-CO_2 pollutants emitted by coal plants using data from a variety of U.S. and Canadian sources. His estimate of the adverse health impacts comes to $29.29/MWh (2012$C), of which 92% comes from sulphur dioxide (SO_2) emissions. He also estimates that the similar harm from gas plant emissions to vary from $1.56 to $6.76 per MWh, with the lower number derived from U.S. Environmental Protection Agency (EPA) data and the higher one coming from a 2005 consulting report to the Ontario Ministry of Environment. Finally, he provides an estimate of the damages from CO_2 emissions using two values of the social cost of carbon, $25/t$CO_2$ and $100/t$CO_2$; the climate harm attributable to coal equals $25-$100 per MWh and that from gas equals $9.88-$39.52/MWh. Then, assuming renewable wind, solar and/or biomass energy replace gas plant output, Dewees concludes that the benefits of pollution averted exceed the FIT rates by $20-$55/MWh for wind and by more than $195/MWh for solar, but that benefits are too low to justify the subsidies provided to biogas and biomass energy and even some hydropower projects.

Econometric studies using U.S. data provide much less support for the use of subsidies. The U.S. keeps track not only of NO_x, SO_2 and CO_2 emissions at the state level, but also emissions by sector and by electricity generator at intervals as short as 15 minutes. As noted earlier (section 3),

[22] According to the World Bank (http://databank.worldbank.org/data/download/GDP.pdf [accessed June 5, 2015]), global GDP was $75.6 trillion in 2013.

studies by Cullen (2013) and Novan (2015) considered the state of the system at the time that wind was produced. During periods of low demand when coal was the marginal generator, the pollution-reducing benefits of wind power were greater than during periods of 'average' demand when a CC gas plant was the marginal asset, or during periods of peak demand when a CT gas asset was the marginal supplier. Accounting for the marginal supplier when wind entered the grid and data at 15-minute intervals for individual generating assets, Cullen (2013) estimated CO_2-offset values of $2.37 to $16.57 per MWh for wind-generated power in the ERCOT system, while offset values for NOx amount to less than $0.83/MWh.

For the same ERCOT system and a similar econometric approach, but using hourly data for a later period, Novan (2015) found that the damages avoided by investing in wind power were $20.76-$23.78/MWh if only carbon dioxide pollution was considered. If reduced emissions of NO_x and SO_2 were also taken into account, the benefits of wind energy in the ERCOT system rose to $23.26-$27.58 per MWh of wind output. However, given that these latter pollutants are part of a cap-and-trade scheme, it is questionable whether it is appropriate to include such damages as the amount of these pollutants will come out at the cap regardless of the wind energy coming into the system.

Finally, Kaffine et al. (2013) used an econometric model to examine the role of wind in Texas (ERCOT), California (California Independent System Operator, CAISO) and U.S. Midwest (Midwest Independent System Operator, MISO). The MISO grid is dominated by coal, the CAISO by gas, and ERCOT is more balanced. For MISO, the authors found that emissions of CO_2 were reduced by an average of 0.92 tCO_2 per MWh of wind; for CAISO, the reduction was 0.29 tCO_2/MWh; and, for ERCOT, the reduction was 0.52 tCO_2/MWh. (For the Pacific Northwest, which is hydro dominated, the emission reductions amounted to less than 0.1 tCO_2/MWh of wind.) The authors find that, even for a social cost of carbon approaching $50/$tCO_2$, the benefits of subsidizing wind were lower than the costs, except for MISO. These results are almost identical to those found in Table 6 above.

Given U.S. subsidies of some $30/MWh or more (see section 7), the externality benefits of wind power (avoided emissions) are too small. That is, the social value of the reduced emissions when wind power substitutes for electricity generated from fossil fuels is not large enough to warrant the subsidization policy. A better policy instrument might well be a carbon tax or trading scheme that would incentivize the substitution of wind power for coal rather than gas.

Finally, it should be noted that the above analyses fail to account for the value of environmental disamenities related to the use of non-fossil fuel sources of energy (discussed in section 4 above). For example, none of the studies examined here took into account the negative health impacts and visual disamenities of wind turbines. Dewees (2013) ignores the environmental harm associated with biomass energy, a renewable energy source that Ontario hopes to use in converted coal plants. Biomass has an impact both on global warming and air pollution. In the U.S., the main argument for reducing or eliminating coal plants relates to the negative impact of coal plants on asthma and other health, primarily in children. In that case, it is difficult to argue in favor of biomass over fossil fuels, especially natural gas, which is why the U.S. has not implemented policies promoting biomass generation (see van Kooten 2015).

Table 7: Post-Tax Subsidies by Energy Type and Externalities ($ billions)

ITEM	2013	2015
Petroleum		
Post-tax subsidy	1,613	1,497
Pre-tax subsidy	267	135
Externalities	1,121	1,162
• Global warming	202	209
• Local air pollution	291	299
• Other	629	654
Foregone consumption tax revenue	224	200
Coal		
Post-tax subsidy	2,530	3,147
Pre-tax subsidy	5	5
Externalities	2,506	3,123
• Global warming	617	750
• Local air pollution	1,889	2,372
Foregone consumption tax revenue	19	20
Natural Gas		
Post-tax subsidy	482	510
Pre-tax subsidy	112	93
Externalities	322	371
• Global warming	267	308
• Local air pollution	56	62
Foregone consumption tax revenue	48	46
TOTAL		
Post-tax subsidy	4,625	5,154
Pre-tax subsidy	385	234
Externalities	3,950	4,655
• Global warming	1,086	1,268
• Local air pollution	2,235	2,734
• Other	629	654
Foregone consumption tax revenue	291	264

Source: Coady et al (2015)

Finally, little is really known about the externality costs associated with today's use of fossil fuels for generating electricity, aside from the general observation that emissions of SO_2, NO_x, particulates and other pollutants deteriorate air quality. The link between these pollutants and health is not always straightforward, while emissions of pollutants such as SO_2 are known to reduce climate change impacts due to their albedo properties. Further, many of these pollutants have been greatly reduced by new generation technologies and the retrofitting of older thermal power plants. Thus, for example, European SO_2 emissions fell by 76% between 1990 and 2009 as a consequence of the adoption of emission targets, with all countries exceeding the targeted reductions.[23] In Ontario, for example, Koop et al. (2010) found no evidence to suggest that emissions from coal plants posed a threat to health. Meanwhile, data from Environment Canada indicates that all of the pollutants have declined significantly in southern Ontario, even though the region is impacted by pollutants drifting in from U.S. sources.[24]

In rich countries, carbon dioxide emissions are the main driver behind policies to reduce reliance on fossil fuels. One way to reduce CO_2 emissions from coal and natural gas is to replace fossil fuel generation of electricity with wind generation. In low- and middle-income countries, on the other hand, burning of biomass and burning of fossil fuels for heating and electricity are often a major threat to human health. Extensive expansion of wind power may help reduce those harmful emissions and might even be financially attractive. In developing countries, therefore, wind power may have an important role because of a combination of health benefits from improved local air quality, financial benefits to small-scale wind developments that counter the adverse impacts of unreliable national grids and high costs of back-up diesel power, and financial incentives for creating carbon credits under the Clean Development Mechanism (CDM) of the Kyoto Protocol (as discussed in section 7).

5. Economics of Electricity Markets

Electricity is an unusual commodity in that production and consumption occur simultaneously. Unlike other markets, there is no mechanism that enables consumers and producers to 'discover' the market clearing price over a period of time; rather, the market for electricity must clear continuously and instantaneously. Nonetheless, supply and demand for electricity remain the essential means for describing the underlying processes that enable the electricity grid to function.

Electricity has historically been a regulated commodity, either provided by a single private company or a publicly-owned enterprise, because the provision of electricity was and often continues to be viewed as inherently monopolistic due to economies of scale. Generation, transmission, distribution, and marketing and retail sales were considered inseparable, with

[23] http://www.eea.europa.eu/data-and-maps/indicators/eea-32-sulphur-dioxide-so2-emissions-1/assessment-1 [accessed June 29, 2015].
[24] See http://www.yourenvironment.ca [accessed June 30, 2015].

generation itself considered inherently monopolistic. Thus, the power industry was horizontally and vertically integrated. However, developments in generation technology (e.g., advances in CC gas after the 1980s), information technology (e.g., wireless/remote control, computerized billing), et cetera, facilitated competition and the ability of governments to deregulate the electricity system.

Economists subsequently recommended deregulation of markets to improve efficiency and lower the prices consumers pay for electricity, although lower prices are not always the outcome. Lower prices will not come about if, prior to deregulation, the government had intervened to keep prices below marginal cost. Deregulation should follow the 'textbook' economics approach, which requires a number of components according to Paul Joskow (2008a; Joskow and Tirole 2006, 2007). The main ones are briefly summarized as follows:

- Privatization of state-owned electricity systems requires hard budget constraints and incentives to improve performance so that it becomes difficult for governments to pursue costly political agendas. That is, governments should not even be able to signal that going back to a regulated market is an option.
- The four segments of the vertical chain need to be separated. The generation and marketing/retail segments can be opened to competition, but transmission and distribution will likely need to be left in the hands of the public, either through ownership or regulation.
- The generation segment needs to be horizontally restructured to make it competitive. There should be a wholesale market for generating services, but care must be taken not to vest too much generation capacity with one or a few firms which can then exercise market power.
- A well-designed forward capacity market is needed to ensure adequate investment to meet future needs.
- To allocate scarce resources, voluntary public wholesale spot energy and operating reserve market institutions are needed to balance supply and demand of electricity in real time. The economics of wholesale markets is discussed in detail in Joskow and Tirole (2007).
- There usually exists a suitable geo-political region that comprises a certain number of generation assets and a transmission and distribution network that services customers. It is expedient and necessary to ring a fence around such electricity assets and create a single independent system operator (ISO) "to manage the operation of the network, to schedule generation to meet demand and to maintain the physical parameters of the network (frequency, voltage, stability), and to guide investments in transmission infrastructure to meet reliability and economic standards" (Joskow 2008a, p.12). As noted above, the ISO might own and operate the transmission and distribution network, and interties to other regions as well, although interties might be jointly owned. The ring could, of course, be broadened to include two or more systems that would then be operated as a single unit.
- Various demand-side agents are also required to inject competition on the retail side. While

a smart grid could facilitate this, retail competition is not necessary for demand response (discussed later). As Joskow (2008a, p.34) notes, competitive retail markets do not require individual (small) consumers to respond to real time prices, but it does require retail suppliers, also known as load serving entities (LSEs), to compete for customers. Indeed, a second-best optimum (given that some retail customers are price insensitive) can occur with retail and generation (wholesale) competition provided (Joskow and Tirole 2006, pp.61-62): real-time wholesale prices reflect social opportunity costs; if needed, rationing is orderly and makes use of all generating capacity; LSEs purchase electricity in the wholesale market at real-time prices to supply their customers' load; retail consumers who can react to real-time prices are not rationed, while, for those that are price insensitive, LSEs can enter into ex ante price contingent rationing contracts; and consumers have the same load profiles subject to scaling (i.e., consumers' loads follow the same phase profile).

Given that our concern in this paper is on wind energy, we focus primarily but not exclusively on generation. In the discussion that follows, it is assumed that the market for generation services is deregulated so that there is an open and competitive wholesale market; the operation of transmission and distribution is assumed to fall under the purview of the government (publicly provided or regulated) and there is competition in retail markets. Generators bid services (a price and output/capacity combination) 24 hours in advance of delivery, although they have the opportunity to change their bids within a pre-specified range up to one hour prior to delivery, with provision for unforeseen breakdowns dealt with through a competitive ancillary services market where generators receive a payment for standby reserves (Joskow 2006; Joskow and Tirole 2007). Both the wholesale generation market and the markets for ancillary services are described below. Further, it is assumed that there exists an independent system operator that oversees the allocation of load to various generation assets according to their marginal costs, regulates transmission and delivery, and has some say in new investment in generators. Demand response and retail competition are also discussed.

Load Duration and the Optimal Mix of Generation Assets

The annual demand for electricity in a region is represented by the load duration curve, which is constructed by arranging the hourly loads for a particular year from highest to lowest. The minimum load during the year is referred to as the baseload because it is the minimum power that must be delivered to the grid at every moment throughout the year. Unlike the invariant baseload, the peak load represents the maximum power that must be delivered to the grid at some point throughout the year. While peak demand varies daily reaching its highest levels each weekday in the early morning or in the late afternoon/early evening, there is one hour during the year when electricity demand reaches an apex. Depending on the system, this will occur during a particularly cold hour within some daily peak period when power is required for heating, or during a particularly warm period when electricity is needed for cooling.

An example of an annual load duration curve is provided in Figure 6 for Ontario's 2008 hourly load; the peak load of nearly 24,000 MW occurred in June when power was needed for cooling and not heating.[25] The baseload during the year was close to 11,000 MW, accounting for 68% of the total annual demand in this system. The peak load period can be defined as the 1,800 hours with the highest demand, although these hours are scattered throughout the year; in the figure, peak load constitutes only 1.7% of total annual demand. Finally, 'load following' represents the demand for electricity greater than baseload but less than the load represented by the load at which peak demand begins (18,000 MW). That is, 'load following' represents the difference between demand in any given hour or 18,000 MW (load in the 1,800th most demanding hour), whichever is smaller, and the baseload (11,000 MW in Figure 6). Load following generators need not respond as quickly as peak load generators because load following requirements are generally forecast well in advance so plants can ramp their output in response. Load following assets might consist of spinning reserves (peaking plants), hydro assets, fast-responding natural gas plants, et cetera, and sometimes baseload facilities. The load duration curve can be used to analyze investments in generating facilities as discussed below.

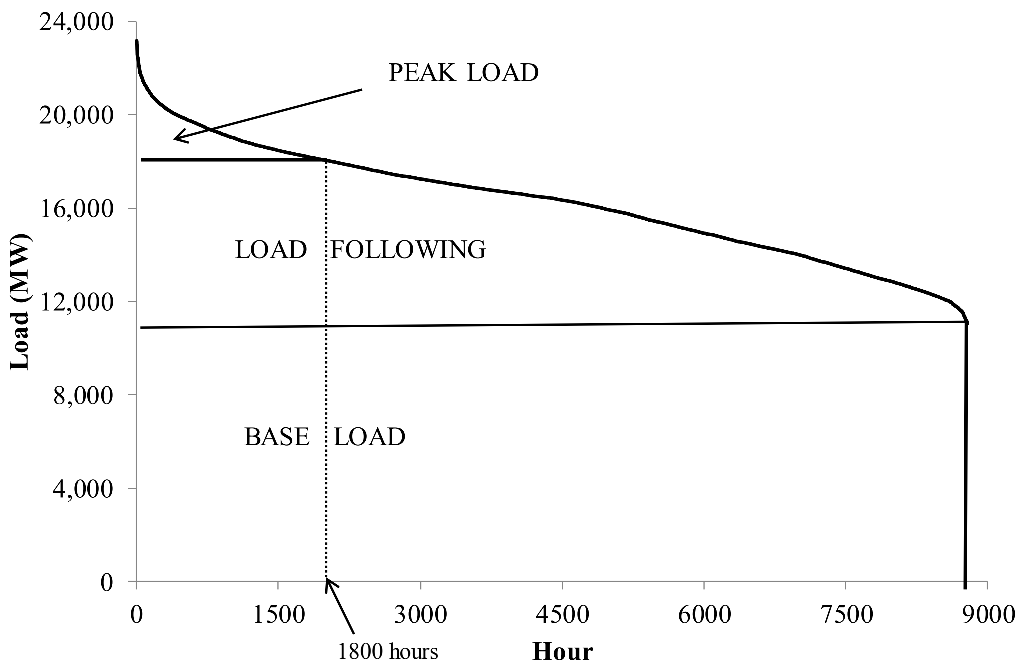

Figure 6: Annual Load Duration Curve Illustrating Concepts of Base and Peak Load

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[25] The Ontario system operator no longer provides hourly load data, but summary data indicate that the summer peak load was 21,363 MW and the winter peak load was 28,000 MW in 2014 (http://www.ieso.ca/Pages/Power-Data/2014-Electricity-Production-Consumption-and-Price-Data.aspx [accessed May 13, 2015]).

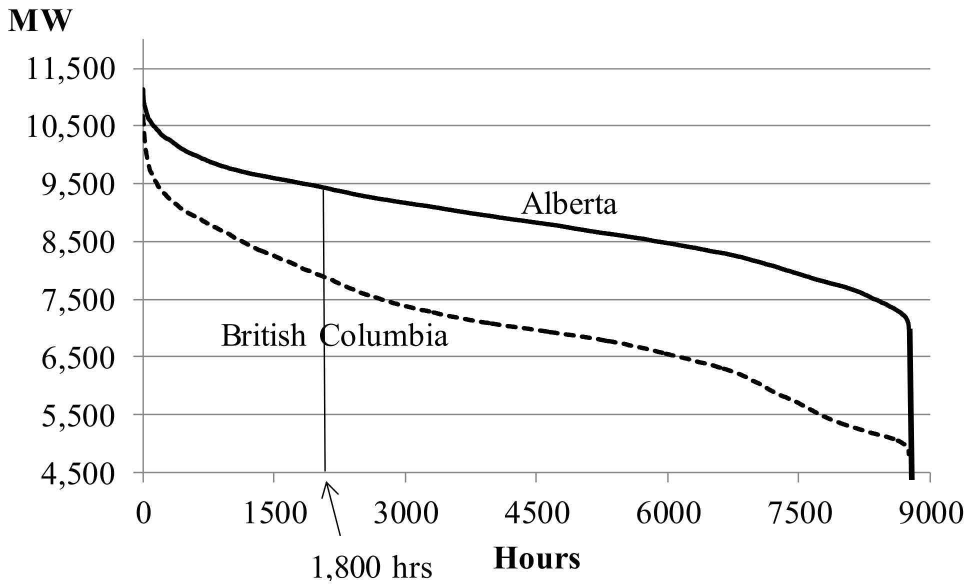


Figure 7: Load Duration Curves for Alberta and British Columbia, 2014

Further examples of load duration curves occur in Figure 7, where 2014 load duration curves for the provinces of Alberta and British Columbia are provided. Compared to Ontario, Alberta's industrial base is more focused on resource extraction, especially of oil and gas. Further, Albertans heat their homes primarily with natural gas, and heat and humidity are less of a problem during the summer, so electricity for both heating and cooling is less than that required in Ontario (even after adjusting for differing market sizes). This explains why the difference between peak and baseload is smaller for Alberta than Ontario, with peak generation accounting for only 1.0% of total generation in Alberta (1.7% in Ontario) and baseload for 78.6% compared to 68.0% in Ontario. In this regard, BC's load profile is much closer to that of Ontario than its neighbor – peak generation accounts for 2.4% of BC's needs while baseload accounts for 68.2%. This implies that Ontario and British Columbia will need to rely on peaking plants – fast-responding gas/diesel plants, hydroelectric facilities and/or imports – to a greater extent than Alberta. In 2014, 24% of Ontario's electricity was generated from hydro sources and 10% from gas; British Columbia relies almost entirely on hydroelectricity with a single gas plant of 900-MW capacity providing electricity when absolutely needed.

Screening Curves

The concept of a 'screening curve' is used to determine how much an electricity producer or system operator would invest in various generating technologies (Stoft 2002, pp.33-39). The method for determining the optimal investment in generating capacity is illustrated using Figure 8 (see Joskow 2006; Fox 2011). When using the screening curve method to calculate a least costs generating mix, it is assumed that demand is invariant (load remains fixed); with deregulation, this procedure is only useful as a guide for economic planning.

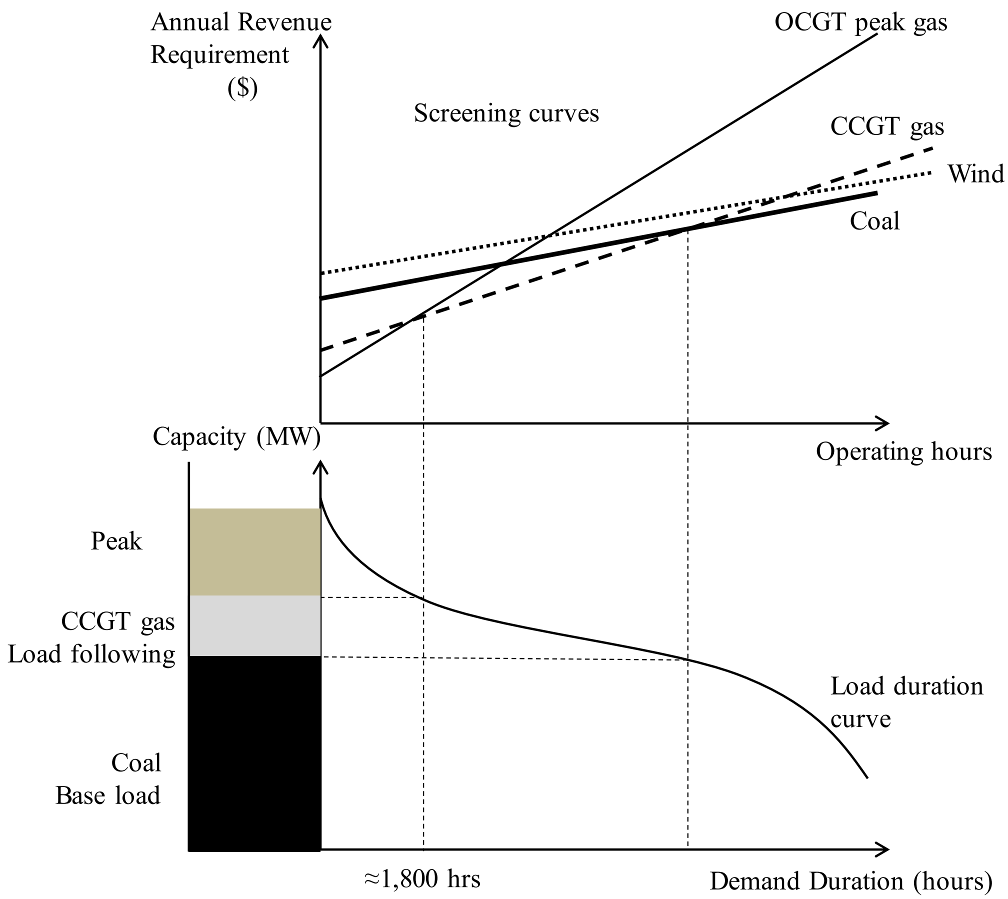


Figure 8: Use of Screening Curves to Determine Optimal Investment in Generating Capacity

The screening curve for generating asset *k* can be stated mathematically as:

(3) $\mathrm{ARR_k} = \mathrm{ACC_k} + VC_k \times h_k$,

where $\mathrm{ARR_k}$ is the annual revenue required per unit of capacity (MW) for generator *k*, $\mathrm{ACC_k}$ is the annualized fixed cost, VC_k is the variable cost component (slope of the screening curve), and h_k is the duration (measured in hours per year) that asset *k* will generate power.

The intercept of a screening curve with the vertical axis is determined by the 'overnight cost', which refers to the cost of all material, labor, fuel, et cetera, needed to construct the facility if that cost were incurred at a single point in time – as if the facility were constructed overnight. This fixed cost is then annualized using equation (1) above. The slope of a screening curve is determined by the variable operating costs, of which fuel costs are usually the most important. The variable fuel cost is expressed in $/MWh and is converted to the same units as the fixed cost component ($/MW) by multiplying by operating hours (see Stoft 2002, pp.34-35). Since the lifetime of a power plant generally ranges from about 20 years for wind turbines to 50 years or more for coal plants, the intercept and slope of a screening curve are based on expectations concerning upfront construction (capital) costs, annual operating and maintenance (O&M) costs, and future fuel prices.

Screening curves are used in conjunction with the load duration curve to determine the optimal capacities of various generation types to install, given current and future costs and prices, and rational expectations about future policy (Muth 1961). The optimal capacity in turn is related to the number of hours of the year that a generator is expected to operate. Thus, a coal plant is expected to deliver power to the system for 7,450 hours or more during a year, or about 85% of the time. A peaking plant might operate at most perhaps 1,800 hours annually (≈20%), but hours are not contiguous so such a plant needs to ramp up and down quickly, and/or start up and shut down frequently. Some peaking plants might operate for less than 50 hours per year.

The generation type with the lowest overnight (capital or construction) cost is also the type that usually has the highest operating costs (screening curve with greatest slope), because it functions for short periods providing peak power. Such assets tend to be an open (simple) cycle, combustion turbine (CT gas) that operates much like a diesel or jet engine: by providing more fuel (applying pressure to the 'gas pedal'), the engine (which might be idling) immediately speeds up generating more power; by providing less fuel, the engine's power is reduced in direct proportion to the reduction in fuel.

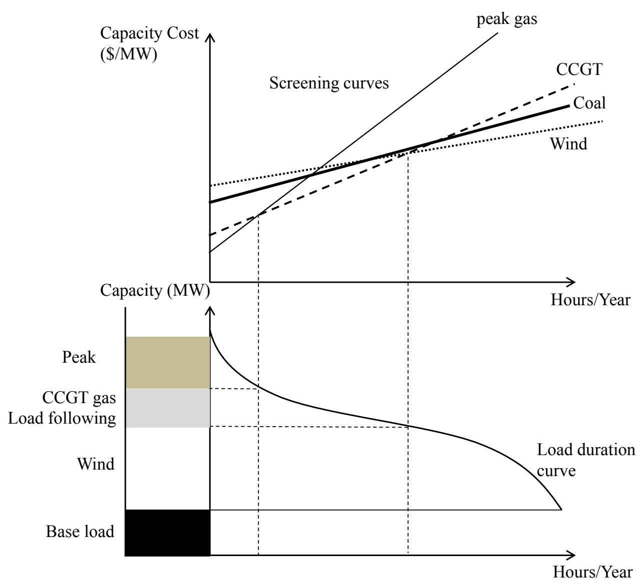
In contrast to a CT gas thermal power plant, a combined-cycle gas turbine (CC gas) facility not only uses the turbine's spinning blades to generate power but also employs the excess heat that would otherwise be wasted in a CT gas plant to fuel a boiler that generates additional electricity. A CC gas facility is expected to operate for longer periods since, in contrast to CT gas units, it is difficult to increase or reduce power rapidly as the boiler takes longer to gain or lose pressure and thus heat. As a result, CC gas plants are generally not used as peaking facilities but, rather, to provide baseload and load following services.

Coal-fired and nuclear power plants have the highest construction costs but the lowest fuel costs. Such facilities are expected to remain in continuous operation throughout the year, only shutting down for routine maintenance or unexpected outages. As indicated in Figure 8, the screening curves and their intersection, along with the load duration curve, determine the optimal mix of generating assets (Joskow 2006, 2008b; Stoft 2002).

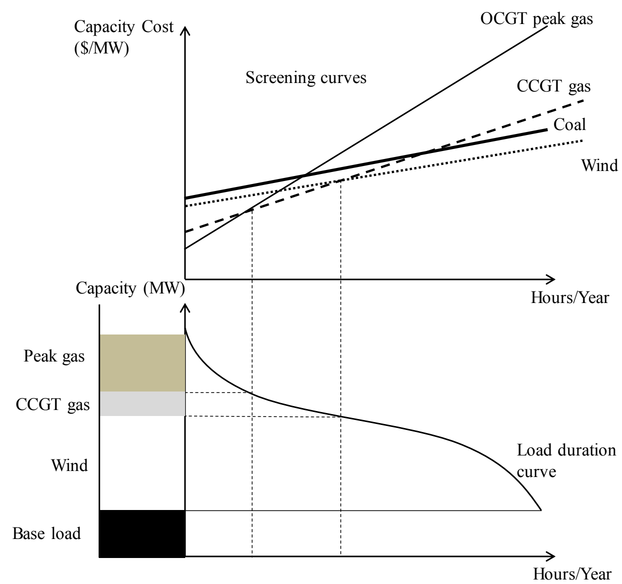
Overnight costs of installing wind turbines are generally higher than those of gas and coal plants, while fixed O&M costs can also be high (see Table 4). The major drawback with wind energy is its low capacity factors (low CF implies high LCOE) and related unreliability, which makes it unsuited for providing baseload power. Although it is possible to examine the wind investments that the system operator might consider making, adjustments to the 'optimal' generating mix need to take into account intermittency. That is, while the use of screening curves remains useful for analyzing investments in capacity and the use of market incentives to mitigate use of fossil fuels in the generation of electricity, the procedure is no longer as straightforward as indicated in Figure 8 (Fox 2011).[26]

Carbon Taxes and Feed-in Tariffs

Climate policies also affect the determination of the optimal generating mix. Suppose that the authority wishes to reduce the use of fossil fuels in the generating mix by incentivizing electricity production from clean energy. One policy is to use a carbon tax, which increases the slopes of the screening curves for coal, natural gas and oil/diesel. Another is to use a feed-in tariff (FIT) that guarantees the developer of renewable energy a fixed price for electricity, with the difference between the FIT and the market price constituting a per-unit subsidy. In Ontario, for example, the *Green Energy and Green Economy Act* (May 2009) guaranteed onshore wind producers 13.5¢ per kilowatt hour (kWh) and offshore wind producers 13.8¢/kWh (van Kooten 2013a, pp.375-376).[27] The effects of a carbon tax and a FIT on the generating mix in Figure 8 are illustrated, respectively, in panels (a) and (b) of Figure 9. More detailed discussion and additional diagrams are found in the Appendix.



(a) Carbon Tax



(b) Feed-in Tariff

Figure 9: Effect of Carbon Taxes and Feed-in Tariffs on Optimal Generation Mix

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[26] It is useful to compare Fox (2011) with van Kooten (2012b) as they come to the same conclusions using quite different approaches. This is discussed further below and in section 6.

[27] In Germany, a feed-in premium is used; it varies by location to promote the siting of wind turbines in low wind locations but is essentially the same as a FIT (see Hitaj et al. 2015).

A carbon tax leaves the screening curve for wind unchanged but causes the slopes of the fossil fuel curves to increase; the FIT leaves the screening curves for fossil fuel options unchanged while shifting the curve for wind downwards. In both cases, wind should be chosen to provide baseload and much load-following capacity. Some CC gas and peak gas capacity are also retained, but coal is left entirely out of the mix. However, wind energy is too unreliable to be used for baseload capacity; where coal is preferred as baseload to CC gas (see Figure 8), the system should optimally still rely on coal to provide reliable baseload capacity. Only if the price of gas is sufficiently low compared to coal might it be optimal to remove coal from the generation mix. When comparing the carbon tax and feed-in tariff in Figure 9, it appears that the tax reduces natural gas capacity by less than does the FIT, and that wind capacity would be greater under a FIT program than with a carbon tax, although the final outcome would depend on the size of each. However, given the variability of wind output, it will be necessary to backstop wind by investing in additional gas capacity as reserve (as discussed in section 6 and Figure 15). Finally, the optimal generation mix will also depend on local conditions, such as the availability of hydraulics, wind resources (which determine the CF), and natural gas and coal deposits.

Renewable Energy and Intermittency

Notice that the diagrams have left out other intermittent renewable energy sources (mainly solar), biomass and hydraulics. Solar energy can be treated much like wind, except it is less attractive than wind because its overnight cost and LCOE are much higher than those of any other generation source (Table 4). Yet, solar power has an advantage: it is available during the day when demand is high, while wind generation is often greatest at times when demand is low. While electricity from biomass is more reliable than that from wind, solar, wave and tidal sources, biomass as an energy source is also controversial, partly because it is not carbon neutral (see van Kooten 2015).

What about hydropower where energy is stored behind a dam so that electricity is dispatchable – controllable by the system operator? It is first necessary to determine the extent to which the load can be generated from hydro: What is the true hydro capacity taking into account fluctuations in generating capacity as reservoir levels change? If the realizable capacity exceeds the peak load and there is fail-safe reliability in the system in case a generator or an entire dam fails or there is a drought, then there may be no need for non-hydro generation. This is rare, however, since even systems that rely almost exclusively on hydropower have some ability to generate electricity from a reliable, fossil fuel thermal power source, or can obtain power through a transmission intertie with another jurisdiction. As demonstrated by Kaffine et al. (2013) and van Kooten (2010), for grids with sufficient hydro resources, adding wind power provides little in the way of reduced CO_2 emissions.

With intermittent sources of energy, electricity is generally deemed non-dispatchable, so it must be taken by the system when it is generated. This creates a problem because any generators that are online when intermittent power enters the grid must adjust their output to accommodate the intermittent supply. Alternatively, suppliers of intermittent renewable energy must reduce output or insure against a loss of power by providing output from storage or from a coupled peak gas generator. The problem remains the same in either case: the load to be met by fossil fuel generators or from storage has greater variability and is less predictable than the load itself (see Figures 5 and 10). This increase in variability leads to grid instability when extant thermal generators are unable to follow fluctuations in load, which is more acute with greater penetration of intermittent renewables into the system.

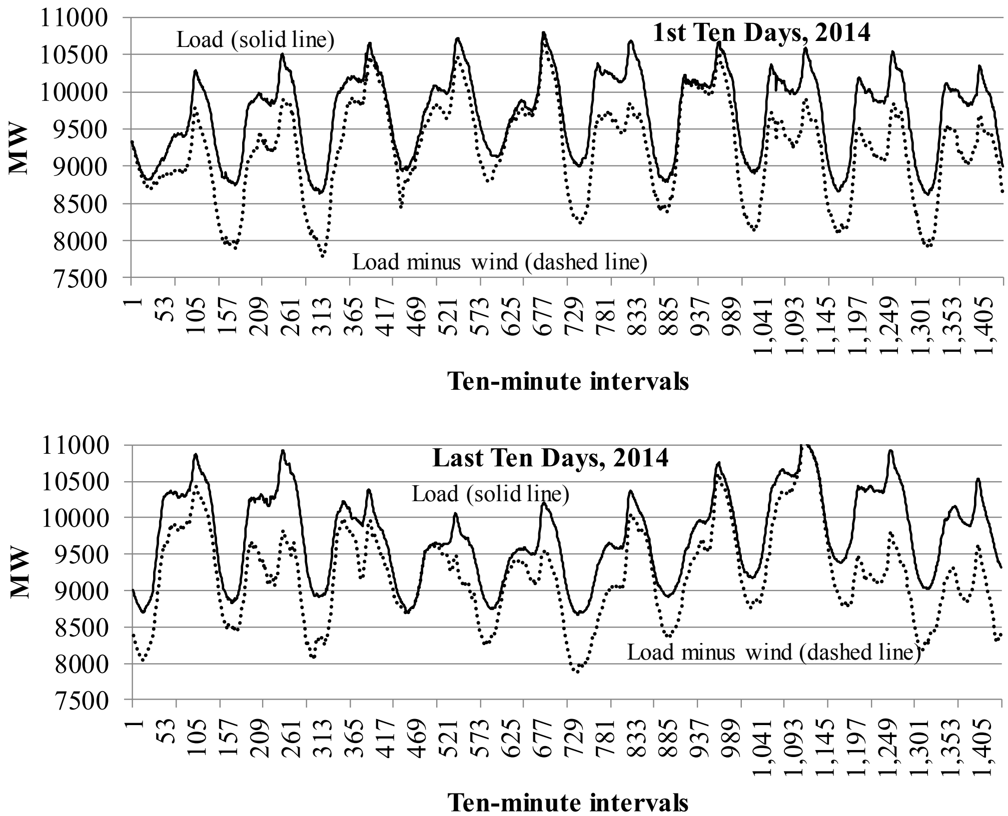

Figure 10: Effect of Wind on Load to be met by Remaining Generators in the Grid, First and Last Ten Days, Alberta Electric System, 2014

The problem of intermittency is illustrated using the Alberta electricity grid for which load and wind generation are available at 10-minute intervals. In Figure 10, we plot the load and the load minus wind for the first (upper panel) and last (lower panel) ten days in 2014 (note the diurnal pattern). The capacity of all wind turbines in Alberta was 1,088 MW in 2013 and 1,434 MW in 2014. Wind generation was below 100 MW on January 1, 3, 5 and 7, while the respective first-of-year and end-of-year capacity factors were 33.5% and 38.1%. The CF for the entire year was close to 28%. These capacity factors compare with the CFs realized for offshore wind farms, primarily because the wind farms in Alberta are eastward of the Rocky Mountains where wind profiles are best suited for the placement of wind farms (McWilliam et al. 2012). Overall, however, the introduction of non-dispatchable or 'must-take' wind generated electricity into the market results in increased variability that potentially increases the difference between peaks and troughs. This greater variability requires the remaining generating assets to ramp up and down more quickly than previously, leading to increased costs, greater need for peak resources and reserves, and lower returns to existing plants. This is illustrated below.

Balancing Demand and Supply: Load and the Supply Stack

An alternative approach to screening curves for analyzing the impact of intermittency and investment in generating capacity of various types employs the concepts of demand and supply directly.[28] Before investigating the impact of wind on an existing electricity system, consider the economics of power generation.

Economics of Power Systems

In a deregulated wholesale market, generators bid in advance to produce a certain amount of electricity at a particular price based on their expected marginal costs at the time they are to deliver power to the grid. The system operator uses this to create an economic merit order or supply stack as indicated in Figure 11. Baseload coal, nuclear and CC gas generators (denoted G0) will bid in at a very low or even zero marginal cost to ensure that they are not taken off line. This is because, in general, baseload generators wish to ensure that their output is taken to avoid high costs associated with ramping generation – they simply cannot ramp their power production up and down very quickly. Other generators can ramp at various rates, encounter different fuel costs, and so on, with these factors leading them to bid in their power at various prices representing their marginal costs. Thus, generator G1 has a lower marginal operating cost than G2, and so on.

Assume that retail prices are fixed so that there is no demand response to changes in price. Then the load is given for any hour and the demand function is represented by a vertical line – that is, the same electricity is demanded regardless of the price in the wholesale market. In Figure 11, the minimum demand is given by D* so that baseload is q^*. In that case, the resulting price can fall anywhere between zero and the marginal cost (bid price) of generator G1. If price is zero, the baseload generators which bid in at zero or near zero marginal cost might earn no quasi-rent (QR); indeed, any generator with a non-zero marginal operating cost that bids in at zero cost would lose money that it would have to make up for operating in subsequent hours when demand

[28] To determine the optimal generation mix requires the construction of an inter-temporal mathematical programming model that allows for decommissioning of fossil fuel assets and investments in renewable energy (e.g., van Kooten 2010, 2012b).

exceeds baseload.

Suppose that demand in any given hour is D^0 so that the marginal generator is G2 and the wholesale price is P^0. This generator would operate below its rated capacity because there is no need for additional power beyond q^0. If G2 is incapable of generating at less than capacity, it is overlooked and G3 becomes the marginal generator and the price received by all generators will rise. In any event, the wholesale price is determined by the marginal generator. If G2 is marginal, G0 and G1 are infra-marginal generators that earn quasi-rents of QR^0 and QR^1, respectively. These quasi-rents (also known as producer surplus) are earnings to set against fixed costs. Without adequate QRs, investors would have no incentive to build power plants. As Joskow (2006) points out, quasi-rents "must be earned by a peaking turbine to make competitive entry financially attractive and to support least cost investment in all technology options."

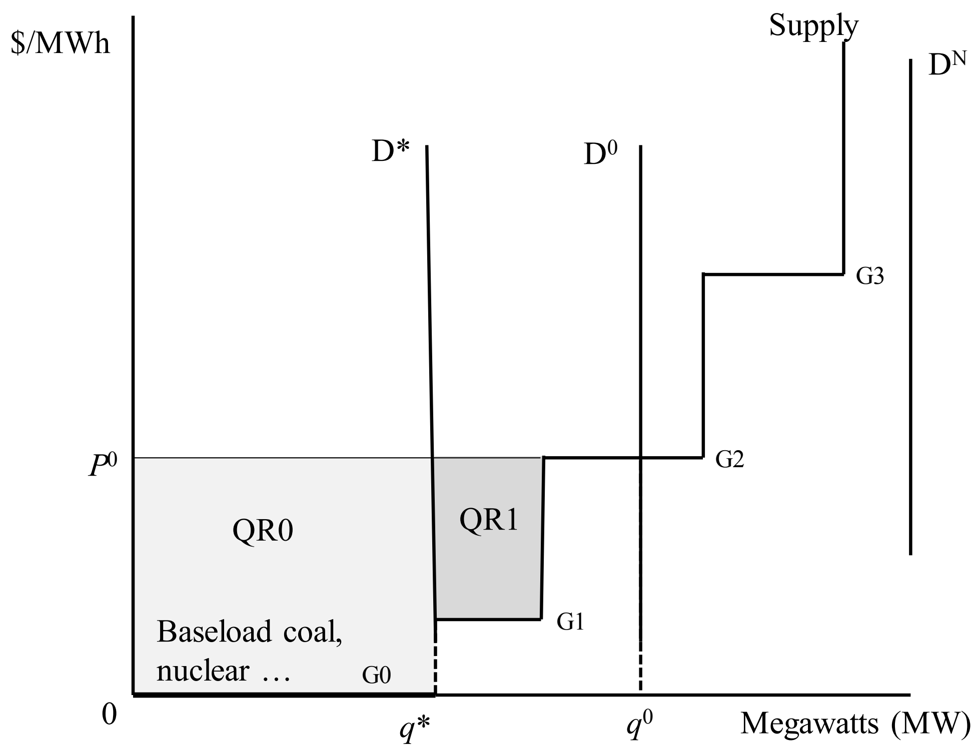

Figure 11: Wholesale Market Electricity Supply Stack and Quasi-Rents, No Demand Response

There is a problem in the market when demand (load) exceeds the capacity of the system. Suppose G3 is the highest cost generating source and that there are no other generators or interconnections to call upon. There is a vertical supply curve and a vertical demand curve D^N; without demand response, there is no well-defined price to clear the market so that the system operator must rely on non-price rationing schemes such as rolling blackouts (Joskow 2006).

Demand response does not require real-time pricing or even time-of-use pricing (discussed below). All that is needed is a sufficiently large electricity user who can be made to respond to prices so that the demand function is no longer totally inelastic as in Figure 11, but is downward sloping (so there is some elasticity) as in Figure 12. The demander could be a processing or manufacturing facility (e.g., sawmill, pulp mill) which is incentivized to respond to increases in system load beyond some sort of tipping point where the load encroaches upon the system capacity. It could also be an aggregator that has signed up commercial, industrial and residential power users, and coordinates their electricity use through wireless controllers on hot-water tanks and heating/air-conditioning (HAC) units, for example. Such a service company has bundled electricity demand and thereby has the ability to increase or reduce system load quickly in response to prices. In the absence of real-time pricing at the retail level, this can be done through a load-shedding contract with the electric system operator or a process where demand responders bid their load reduction in the reserve market (discussed below).

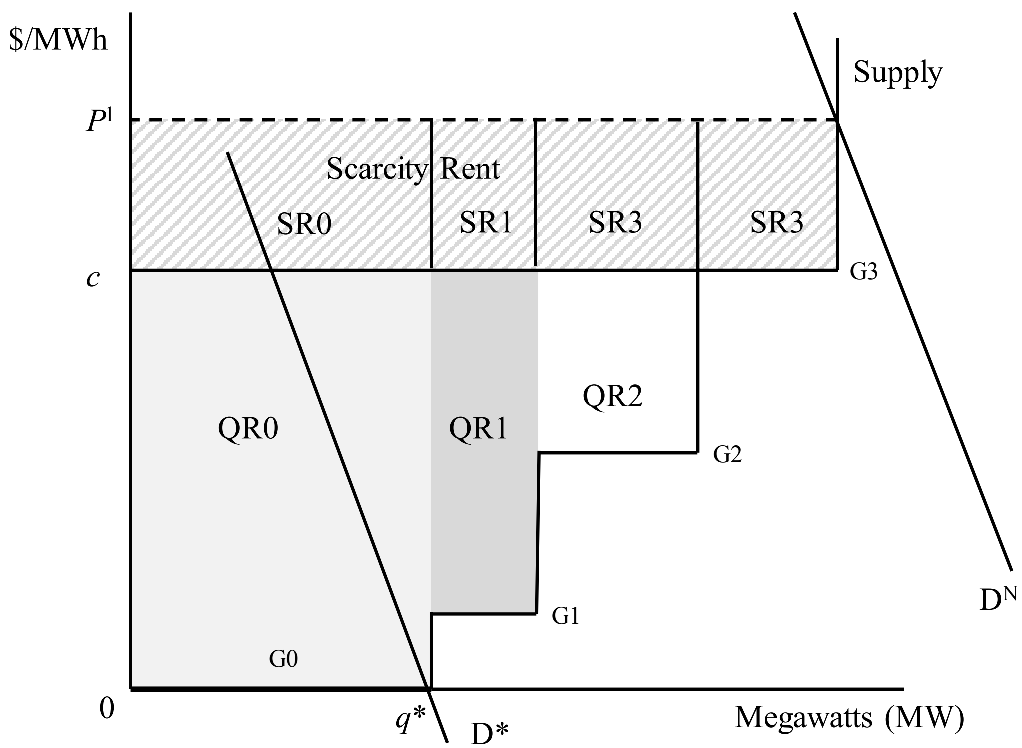

Figure 12: Wholesale Electricity Supply Stack and Rents with Demand Response

The implication of demand response in the wholesale electricity market is illustrated with the aid of Figure 12. In the figure, the marginal supplier is G3 but, unlike in Figure 11, the market clearing price is defined by the intersection of the supply and demand (D^N) functions. (It is now clear that the price at lowest demand D* is zero.) Further, because there is no other supplier and thus scarcity, the market price P^1 exceeds the cost c of the marginal supplier. As a result all generators in the system earn scarcity rent (SR) over and above their QR, although in practice it might at times be difficult to distinguish the scarcity rent from the quasi-rent for generators G0, G1 and G2. However, scarcity rents are crucial for G3. Without scarcity rent, there might be no incentive for anyone to invest in building marginal generators of type G3. Yet, system operators often place a cap on the extent to which the wholesale price can rise, leading to a loss of essential revenue for the marginal operator – a peak CT gas plant when demand is high and perhaps a coal or CC gas plant when demand is low.

It is the very high prices during times of peak demand, when system capacity is reached, that are most important for creating the scarcity rent, SR3, that incentivizes investment in peak capacity. This lost scarcity rent has been referred to as the net revenue gap or the problem of 'missing money' (Joskow 2006). It is the central problem of resource adequacy, namely "that, when generating capacity is adequate, electricity prices are too low to pay for adequate capacity (Cramton and Stoft 2006, p.8). In practice, although price spikes of $5,000/MWh have been observed, system operators have tended to cap wholesale prices at $250 to $1,000 per MWh to mitigate market power (ibid.). The Alberta Electric System Operator (AESO), for example, employs a cap of $1,000/MWh, while the Electric Reliability Council of Texas (ERCOT) has a cap price of $9,000/MWh.[29]

When demand intersects supply at a very high price, and there is a cap on the price so the market price greatly exceeds the cap, the system operator will first attempt to shed load. If demand remains higher than supply as a result of the price cap, there is a risk that the operator would need to implement rolling blackouts. At this point, we define the value of lost load (denoted VOLL) as the spot price in a competitive market – that is, it is the value that buyers place on receiving power despite the shortage in its availability (Stoft 2002, pp.154-156). To ensure the stability of the market, the spot price should be permitted to equal VOLL. By capping the wholesale price, there is also no incentive for investors to build marginal or peak plant capacity. Indeed, many system operators set the cap equal to the marginal cost of the peaking generator, which guarantees that the peak plant will be unable to recover a surplus to cover fixed costs.

The problem of 'missing money' is simple to illustrate. Suppose a 400-MW capacity gas plant was expected to operate only 38 hours per year and that, during 28 of those hours, the wholesale price is expected to be $4,500/MWh. By capping the price at $1,000/MWh, each year the marginal operator could potentially lose $98,000 per MW of installed capacity. If the plant had a life expectancy of 30 years and a 4% (8%) discount rate is employed, this implies that the present value of lost revenues ('missing money') would equal $1,694 ($1,104) per kW, or more than $675 ($440) million of revenues. From Table 4, the 'missing money' exceeds the overnight

[29] Wholesale prices in the ERCOT system were deemed inadequate to attract sufficient investment, so the Texas Public Utilities Commission raised the system cap from $5,000/MWh in summer 2014 and to $7,000/MWh in mid-2015. In early 2014, there were 20 incidents when the $5,000 cap was binding (ERCOT 2015, p.11).

construction cost.

It is clear that a deregulated wholesale market would not result in adequate generating resources without some other mechanism to cover the fixed costs of building required capacity. Worse yet, the introduction of intermittent wind energy exacerbates the revenue gap problem. The reason is that wind power will shift the supply stack to the right and reduce prices (as illustrated below); in essence, wind will enter the system at times when the marginal supplier would otherwise be called upon, thereby reducing the number of hours when the marginal supplier would receive the highest price. With or without wind, one mechanism for addressing the revenue gap (missing money) problem is to provide a gas plant with a contract that guarantees a return on capital investment. Another is to use a capacity payment.

Recall that, in some systems, the ISO requires generators to bid in a certain amount of capacity and a price for providing power 24 hours ahead of the hour in which they are to deliver electricity to the market. These bids and their associated generating capacities (supply) are arranged in order yielding a supply stack, which is also referred to as the market merit order because the bids are considered marginal costs and these are arranged from lowest to highest (see Figure 12). If the asset is subsequently chosen, it receives the spot price in the wholesale market for the hour that electricity is actually supplied. To avoid the missing money problem, economists recommend a capacity payment – a market-determined payment for the capacity that a company is willing to commit in advance of the hour in which power is to be delivered (Joskow 2006; Joskow and Tirole 2007). The capacity payment is to be made not only to the marginal supplier but to all generators including baseload generators. Further, such a capacity payment should not be confused with payments made to provide ancillary services, such as backup power in the eventuality of a loss of power somewhere in the system.

Ancillary Services and the Markets for Reserves

Because demand and supply of electricity must balance at all times, there is a need for ancillary services. System operators are required by a regulatory authority to maintain adequate reserves.[30] Ancillary services are not homogeneous, and even how they are defined and handled may differ across jurisdictions. Frequency regulation services address second-by-second, minute-by-minute fluctuations in demand and supply so that grid reliability is maintained – that the grid delivers 120 volts at 60 Hz (in North America) or 240 volts at 50 Hz (Europe). Regulating reserves operate over a time frame of seconds to upwards of 10 minutes, and generators providing such reserves must be operating or 'spinning' (Stoft 2002, pp.307-308). Such short-term fluctuations are often satisfied by on-line generators, including some baseload plants that are able to vary

[30] One regulatory authority is the North American Electric Reliability Corporation http://www.nerc.com, while a regional body is the Western Electricity Coordinating Council, which coordinate electricity production and transmission in western Canada and U.S.

their output slightly over some range. In addition, CT gas plants operating below capacity or idling in standby mode ('spinning reserve') can be deployed, since they can readily adjust output. For example, generator G3 in Figure 12 is not operating at full capacity at price P^1 and can easily adjust supply. Storage devices, such as batteries and flywheels, might also be used in a regulatory capacity as might hydropower. Automated generation control (AGC), which is also known as regulation, is used to manage small fluctuations in the supply-load balance.

Operating and replacement reserves are also needed – the former can also be referred to as spinning reserves, while the latter are considered non-spinning reserves. Operating reserves "typically consist of 'spinning reserves', which can be fully ramped up to supply a specified rate of electric energy production in less than 10 minutes, and 'non-spinning reserves', which can be fully ramped up to supply energy in up to 30 minutes (60 minutes in some places)" (Joskow and Tirole 2007, p.78). Non-spinning generators are divided according to whether they can provide power from a cold start within ten minutes or at most 30 minutes; such reserves usually consist of gas turbines.[31] Some component of the non-spinning reserves is needed to handle emergencies – the contingency that a power plant goes 'off line'. Spinning and non-spinning reserves generally equal about 10-12% of system capacity, or more depending on the generation mix of the system.

Finally, ancillary services include replacement reserves. This refers to the market for cold- (black-) start capacity, which is an investment market that is directed by the ISO. The ISO may or may not provide incentives to investors to construct power plants that might be needed to address a future emergency.

Markets for ancillary services can be established in a fashion similar to that of the real-time market, except that units receive the market-determined payment for their reserve position plus the market clearing price for any electricity they are asked to dispatch. Reserve markets are not a necessity, however. In some deregulated markets, the system operator no longer pays for standby functions. Rather, generators simply 'bid' into the generation market and remain on standby on the chance that they will be called upon and receive a high price when they are dispatched.

There are several types of reserve market; the two most common are the markets for 'spinning' and 'non-spinning' reserves. A market for 'non-spinning' reserves is illustrated in Figure 13. Denote the demand for contingency reserves in a given hour by D^C, which is determined by the conditions set out by the regulatory bodies. The various generating units bid their reserves much

[31] The term 'load following' is used to designate generators that are ready to follow shifts in load on time frames that usually do not but could exceed 10 minutes; they are somewhat similar to regulatory reserves. The difference is that load following requirements are generally anticipated (see discussion with respect to Figure 6), while regulating reserves are designed primarily to deal with unanticipated changes in load and supply, although the distinction is not often clear.

like they do in the establishment of the supply stack for generation (see Figure 11). In the ancillary market, peak gas plants and hydroelectric reserves will bid in at a low price because they are the ones that can get off the mark the quickest and they incur the least costs to maintain a reserve position. These assets receive a payment for each unit of capacity they bid into the reserve market. If they are needed, they then receive the reserve payment plus a payment for any power delivered to the grid as determined in the electricity market (Figure 11). The question is whether each generator will receive a reserve payment according to its bid price, so the system operator exercises monopsony power, or if all receive the same payment based on the bid price of the marginal reserve asset. In the latter case, infra-marginal reserve assets receive a quasi-rent as indicated in Figure 13. Of course, the marginal asset receives no quasi-rent in the contingency market and, if called upon, might also not receive quasi-rent in the generation market. That is, a reserve payment mechanism would not address the 'missing money' problem.

In Figure 13, the hydro facility would be the first one to which the system operator would turn for reserve power followed, in turn, by the CT#1 and CT#2 peak providers. With demand D^C only some of the capacity of generator C3 (CT#2) would receive a payment in the market for contingent reserves. Hydroelectricity can be a particularly good provider of ancillary services, although it can also provide baseload power. Hydro can bid in as a low-cost provider in the generating services market or as a low-cost provider of ancillary services. It can play either role, although the makeup of the hydroelectric facilities in the system will determine the role it actually plays.

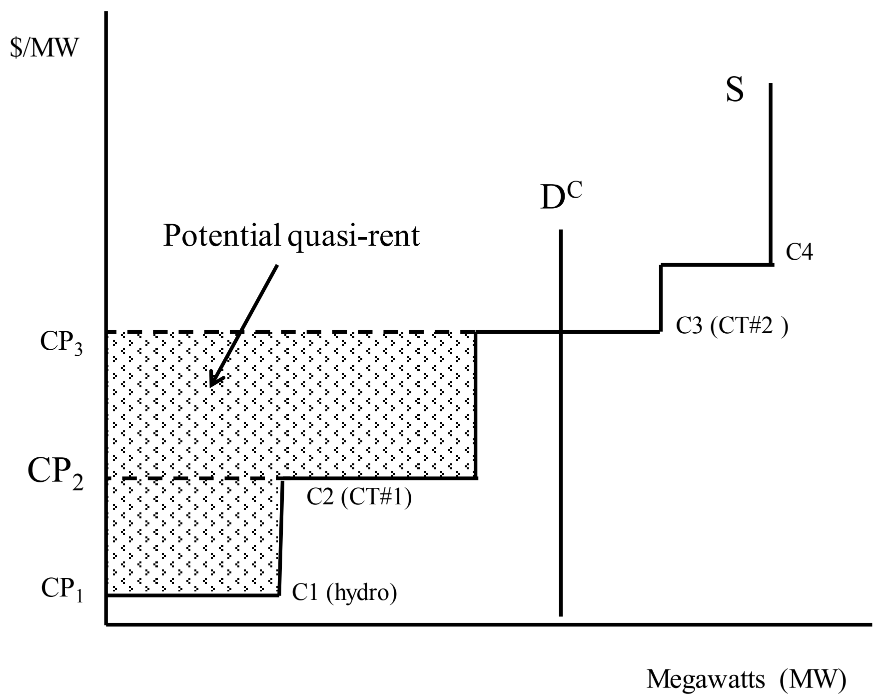

Figure 13: Supply Stack for Non-spinning Contingent Reserves

Demand Response and the Smart Grid

As already indicated in the discussion pertaining to Figure 12, the demand side plays an important role in stabilizing a grid when electricity from intermittent sources enters. There are several aspects to demand management. First, there is the possibility that a particularly large demander, such as a pulp mill, is willing to bid in its load as reserve capacity. A large power user might be willing to shut down all or part of its operation at any given time in exchange for a payment. The effect of a shutdown will shift the demand function or tilt it in such a way that the situation in Figure 11 becomes that of Figure 12. However, this is only one aspect of what is generally meant by demand response.

The purpose of demand management is to increase consumers' responsiveness to prices. This requires at the very minimum a two-tiered, time-of-use pricing system. For example, daytime prices might be higher than nighttime prices, thereby shifting demand for electricity from peak periods to off-peak hours. The lower nighttime prices will cause consumers to delay using their dishwashers, washing machines and so on to evening and nighttime hours. In essence, two-tier pricing results in 'peak shaving' – shifting load from periods of high demand to periods of low demand – but it does not necessarily lead to conservation and reduced CO_2 emissions. It all depends on the makeup of the assets providing power to the grid. Peak shaving could lead to substantial savings in the long run, however, because it would be possible to eliminate perhaps 10% to 15% of total generating capacity that is only meant to service demand during those few peak hours (Joskow 2012, p.40). The same is true when multiple price tiers are employed, but the customer knows in advance what the prices will be at different times of the day. Again this might not be considered true demand response.

True demand response involves real-time pricing (RTP) and differs from tiered pricing because the customer does not know in advance the market price of electricity. As a result, she will need to monitor the price in each period, whether hourly or some shorter period, to determine whether to use electricity for certain tasks. Of course, this can only be done by computers that have been pre-programmed to turn appliances and other electric services on or off depending on the going rate and the state of the system (e.g., room temperature in the case of electric heating or cooling). This requires a 'smart meter' so the customer or a third party can send a signal to a consumer's appliances (refrigerator, freezer, thermostat on the hot water tank, etc.), and smart appliances that have computer chips programmed to respond to the signal. In practice, it makes sense to control only boilers and heating and air conditioning (HAC) units, because these are the largest power users and can easily be controlled via a thermostat whose range can be pre-set. The interaction between electric vehicles and the grid constitutes another promising use of smart meters; batteries might retain sufficient charge to send power to the grid when prices are high, with recharging occurring when prices are low.

Consider the following. The price of electricity and the home's indoor temperature (temperature of the water in the boiler) are the state variables that determine whether an HAC unit or boiler will start up or shut down. Suppose a room is relatively warm so that the air conditioner would normally start up. With a smart grid, the unit might start up only if the price is below some threshold but not if the price is at or above the threshold. On the other hand, if the temperature in the home reaches an upper limit because the values of the state variables (price and temperature) had delayed the HAC service, the air conditioner would now start regardless of the electricity price simply because the consumer is willing to pay for cooling services even at the higher price. Likewise, the state of charge and the time remaining before an electric vehicle must be fully charged could serve, along with electricity prices, as state variables determining whether to discharge or recharge the battery.

Studies indicate that consumers do respond to dynamic price signals (Joskow 2012; Joskow and Wolfram 2012). Real time pricing increases the price elasticity of demand so that the vertical demand curve in Figure 11 becomes downward sloping as in Figure 12; the more price elastic the demand, the flatter the demand curve in Figure 12 becomes. Evidence also indicates that only 20% of consumers experience increased overall costs of electricity, and that a large majority experience reduced power bills (Joskow and Wolfram 2012). Further, it appears that one-third to four-fifths of the costs of installing smart meters can be covered by the savings the utility gains from reduced meter reading expenses and the ability to detect outages (ibid.).

A program to install a smart meter at every customer's location might not be worthwhile, however, because the same technologies are already being exploited by the private sector. Where there are potential benefits from controlling bulk electricity services, such as hot water heating and HAC services, the private sector has already made inroads. Companies have signed up commercial, industrial and residential power users, coordinated their electricity use through wireless controllers on boiler and HAC units, and bundled the ability to increase or reduce the system load quickly. This demand response service is then sold in wholesale markets or under contract with the electric system operator. This has removed the need for smart meters and smart appliances.

In their determination of efficiency in deregulated electricity markets, Joskow and Tirole (2006, 2007) assume competition at the retail level, but that not all consumers are price sensitive. Instead, they require that there exist a sufficient number of load serving entities that compete for retail consumers and purchase electricity in the wholesale market. For price insensitive consumers and assuming that consumers' load profiles are similar (up to a scaling factor), an LSE enters into a contingent contract that enables it to adjust the customer's electricity usage at different price levels. This insures that the retail side of the market responds to changes in prices – an approximation to a smart grid.

Several questions remain to be addressed: What is the impact of dynamic or real-time pricing on CO_2 emissions from the electricity sector? What happens when wind is introduced into a smart grid? While dynamic pricing (with its smart meters and smart appliance) has the potential to reduce electricity use, its main effects appear to come from peak shaving – reducing electricity demand during peak periods and thus the need for peak generation capacity – and a reduction in power bills. Indeed, time-of-use pricing, peak pricing and real-time pricing (even when there are some price incentive consumers represented in the market by their LSE) are generally promoted on the basis of the savings they provide. However, lower power bills contribute to the so-called rebound effect, which economists refer to as the income effect. Savings are spent on other activities that also require electricity as an input, thereby increasing the demand for electricity. While tiered prices lead to peak shaving and thus less production of electricity from gas, say, there is an increase in demand that could also increase reliance on baseload power produced from coal plants that have a higher CO_2-emissions intensity. This rebound effect reduces the CO_2-mitigation benefits of demand management and, in extreme circumstances, might even lead to an increase in CO_2 emissions, a phenomenon known as backfire (Jenkins et al. 2011).[32]

What is the effect of demand management when wind energy enters the electricity system? Some information about smart grids and wind comes from a study by Broeer (2015), who used an agent-based modeling framework, information from a real-time pricing experiment with 1,000 households in Washington's Olympic Peninsula, data on available generator assets, and a profile of wind power output. The purpose of the study was to determine the potential benefits of demand management by examining the effects of price changes occurring at 5-minute intervals and demand responses of 60-second intervals. He found that the initial load is shifted with demand response leading to peak shaving and, in the absence of wind generation, that there is a small reduction of 5% in greenhouse gas emissions. On the other hand, "when wind power is added into the generation mix then the emissions are almost the same at the end of the one week simulation period. In this case only low emitting gas generation is almost entirely displaced by wind power. However, at the same time coal power is forced into a higher cycling and lower efficiency regime" (p.61). The CO_2 benefits of demand management turned out to be much lower than expected and there was evidence of a significant rebound effect as consumers shifted load to other times.

There are other aspects of the 'smart grid' which have implications for intermittent power. To perceive the smart gird only from the perspective of the final consumer is misleading, because the most important aspects of investment to create a smart grid likely relate to the expansion and

[32] Economic theory suggests that a backfire effect is unlikely. One can only get an income effect that overrides the original substitution effect if income was misallocated to begin with – that there is market failure somewhere in the allocation of resources. If so, then policy should first be directed at correcting the market failure.

qualitative improvement of transmission and distribution networks. That is, in addition to remote metering and communication with the end user, a smart gird requires improvements in "remote monitoring and automatic and remote controls of facilities on high-voltage transmission networks, … [and] in remote monitoring, two-way communications, and automatic and remote control of local distribution networks" (Joskow 2012, p.30). Long distance transmission, automated control and better communication among systems are particularly important to efficient integration of intermittent generation.

6. Accommodating Wind in Existing Electricity Grids

From the perspective of mitigating climate change and producing electricity from renewable energy, wind is seen as one of the more promising means of achieving CO_2 emissions reduction targets. Unlike hydro and biomass, wind power is unreliable because wind is an intermittent resource, along with solar, tidal and wave energy. In this section, integration of intermittent wind energy into electricity grids is examined using the tools of the previous sections.

Before proceeding, consider again the levelized cost of electricity (Tables 4 and 5), which indicates that wind might be or soon become competitive with some fossil fuel and hydro technologies and certainly nuclear energy, while PV solar is too costly. But the LCOE says nothing about profitability, as Joskow (2011) has demonstrated. Using his approach, assume that the wholesale price of electricity it 18.5¢/kWh at peak times but that it is 2.5¢/kWh during off-peak times. Further, assume the number of hours per year that the five technologies in Table 8 operate is determined by their capacity factors, but that these hours are not spread in the same way across peak and off-peak hours. Baseload coal and nuclear plants are assumed to operate full out during 3,000 hours of high peak prices; onshore wind is assumed to provide power only during off-peak hours (mainly at night), while offshore wind output is spread more evenly across peak and non-peak hours as indicated in the table; and solar power, when available to the grid, is assumed to be generated during periods of high prices. Given the average LCOEs in Figure 4, the net revenues to one MW of installed capacity for each energy source are calculated and provided in Table 8.

Table 8: Comparison of Operating Costs, Revenues and Net Revenues Accruing to 1 MW of Installed Capacity: A Comparison of Two Dispatchable and Three Intermittent Generating Technologies

Item	Nuclear	Coal	Onshore Wind	Solar	Offshore Wind
Levelized cost ($/MWh)	85.41	22.15	76.41	179.23	102.26
Capacity factor	0.90	0.85	0.30	0.20	0.35
Hours per year	7884	7446	2628	1752	3066
Annual peak hours	3000	3000	0	1752	1533
Annual off-peak hours	4884	4446	2628	0	1533
Annual revenues ($/MW)[a]	$677,100	$666,150	$65,700	$ 324,120	$321,930
Annual costs ($/MW)	$673,372	$164,929	$200,805	$ 314,011	$313,529
Annual net revenue ($/MW)	$3,728	$501,221	– $135,105	$10,109	$ 8,401

[a] Assuming peak and off-peak prices of 18.5¢/kWh and 2.5¢/kWh, respectively.
Source: Author's calculations

In Table 8, nuclear, solar and offshore wind technologies are capable of generating slightly positive returns over a year of operation, somewhere between $3,700 and $10,100 per MW of installed capacity. Returns to a highly advanced coal technology, on the other hand, are more than $0.5 million annually per MW of installed capacity. Meanwhile, without subsidies, onshore wind installations annually lose some $135,000 per MW. While returns to the dispatchable nuclear and coal technologies are reliable, depending only on the peak and off-peak prices, returns to the intermittent technologies are highly dependent on when power is generated, and this can change from one year to the next. It is also clear that solar PV may not be disadvantaged relative to wind despite its higher LCOE, because solar power is more likely to be available to the grid during peak times while wind power often tends to be available during off-peak hours. Of course, these net returns do not include the externality costs, which favor the three intermittent sources of power over coal but perhaps not nuclear energy. However, the point here is that a levelized cost of electricity makes little sense for intermittent technologies, and that the LCOE cannot be used to compare different intermittent renewables against each other or against traditional generation (Joskow 2011).

This approach is also used to provide a rough calculation of the operating costs, revenues and net returns for the Alberta electricity system for 2012 and 2013. This requires data on hourly market (marginal) price data and actual generation by generation assets. However, information pertaining to generation is available only by fuel type; this is a problem only for natural gas as it is used in CT gas, CC gas and co-generation technologies, with the latter comprising 60% or more of electricity generated from natural gas in Alberta. In 2012 and 2013, market prices ranged from $0/MWh to $1,000/MWh, with both prices constituting limits set by the Alberta Electrical System Operator; average prices were $64.32/MWh and $80.19/MWh in 2012 and

2013, respectively. The results in Table 9 indicate that net returns per megawatt of installed capacity were highest for natural gas in both years, followed by coal and hydro; in both 2012 and 2013, returns to wind energy were negative, with losses exceeding $100,000 per MW of capacity in both years. Given that losses were higher in 2012 than 2013 despite the higher capacity factor in 2012 (30% vs 26%), it is clear that the timing of wind production and, thus, the price of electricity was the most likely cause of the higher losses. In contrast, the CF for hydro was much higher in 2012 than 2013 (26% vs 9%), but net returns in 2013 were nonetheless higher because hydropower was produced during times of peak prices as there is some ability in the Alberta system to store water and delay its flow through the generators.

Table 9: Estimated Revenue, Operating Costs and Net Returns to Four Technologies, Price and Generating Data for Alberta, 2012 and 2013

Item	Coal	Gas	Hydro	Wind
		2012		
Generating capacity (MW)	5,690	5,682	900	950
Capacity factor	0.75	0.54	0.26	0.30
Revenue ($/MW per year)	$432,392	$348,226	$150,617	$99,966
Levelized cost of electricity ($/MWh)	$45	$28	$35	$98
Costs ($/MW per year)	$297,635	$133,748	$78,641	$261,814
Net revenue ($/MW per year)	$134,757	$214,478	$71,976	–$161,848
		2013		
Generating capacity (MW)	6,258	5,812	900	1,113
Capacity factor	0.70	0.57	0.09	0.26
Revenue ($/MW per year)	$477,399	$435,614	$90,928	$124,323
Levelized cost of electricity ($/MWh)	$45	$28	$35	$98
Costs ($/MW per year)	$277,789	$139,222	$28,195	$226,079
Net revenue ($/MW per year)	$199,610	$296,392	$62,733	–$101,756

Source: Author’s calculations

Potential Impacts of Integrating Wind into an Electricity Grid

The challenge of balancing an electricity system when power from one or more generators need to fluctuate to accommodate intermittent wind can be illustrated with the aid of Figure 14. In the figure, it is assumed that the existing generation mix was in place before deregulation and has sufficient capacity to meet load requirements; the demand curve is also assumed to be downward sloping. The problem of inadequate resources is put aside for now.

In the deregulated market, generators bid a day in advance to produce a certain amount of electricity at a particular price based on their expected marginal costs at the time they are to deliver power to the grid. The system operator uses bids to create an economic merit order or supply stack as discussed with respect to Figure 11 (and expanded upon in Figure 14). Baseload coal, nuclear and CC gas generators (denoted G0) might bid in at low (or zero) prices to ensure that they are not taken off line and thereby avoid high costs associated with ramping production up and down very quickly. Other generators ramp at various rates, encounter different fuel costs, and so on, with these factors leading them to bid in their power at various prices. Thus, generator G1 has a lower marginal operating cost than G2, et cetera.

Consider the case in Figure 14 where no wind enters the system and suppose that the supply of electricity at some hour is given by S^0. If the demand at that hour is high, say D^0, generators G0 through G7 are asked to deliver power to the grid, with the spot price for that hour, P^0, determined by the marginal cost of generator G7. All generators in the system, including baseload power plants receive P^0, so all but G7 earn quasi-rents. If the demand for that hour is at its lowest, say D^B, then only the baseload generators G0 will be engaged, producing q^B. Generators G1 through G9 are left idle, and no generator earns quasi-rent. Indeed, because G0 generators might have bid in below marginal cost to ensure they would operate in that hour, the spot price might be less than marginal cost so that they actually incur a loss that they recover in subsequent periods by avoiding ramping costs. Finally, G9 might well be an exporter that bids a high price to ensure that it is not chosen to supply the local market, leaving it free to sell power in another market.

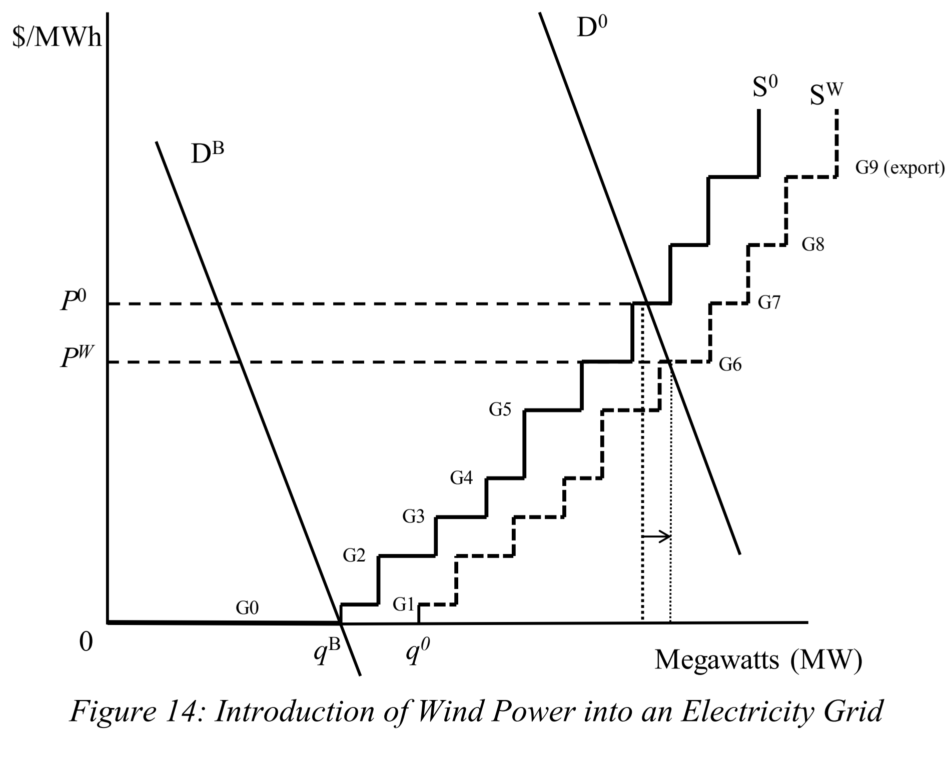

Figure 14: Introduction of Wind Power into an Electricity Grid

It is easy to see how wind destabilizes the system. Assume that wind is non-dispatchable so that any wind power that is produced must be accepted by the system operator. If q^Bq^0 wind power enters the grid, it shifts the supply curve in Figure 14 to the right, from S^0 to S^W (the dashed supply stack). Now, with demand curve D^0, it is no longer G7 that is the marginal producer of electricity; rather, it is the plant with a lower marginal cost, G6. The market clearing price of electricity for that hour falls from P^0 to P^{W}. The introduction of wind power lowers the price of electricity, which will induce consumers to purchase more of it (as indicated by the arrow). If the demand function was perfectly inelastic, the intersection of demand and supply would occur in such a way that generator G5 is the marginal supplier, meaning that price will collapse even further than indicated. On the other hand, if the demand curve is more price elastic than shown, perhaps because RTP is implemented, more electricity is demanded – the greater is the rebound effect. Thus, the introduction of wind power worsens the 'missing money' problem, while reducing CO_2 emissions by less than was anticipated because of a rebound effect.

What does one do with the wind energy $q^{\mathrm{B}}q^0$ if the demand in a given hour is D^B? Clearly, either wind generated power must be curtailed (wasted) or baseload output reduced. Baseload hydropower can easily be adjusted, but not thermal generation. If $q^{\mathrm{B}}q^0$ wind energy could be reliably produced in every period, so it can be considered part of baseload production, then some thermal baseload capacity becomes redundant and can be eliminated – an ideal outcome especially if coal-fired capacity is eliminated. However, wind generated power is not reliable and cannot replace thermal baseload capacity (e.g., see Miskelly and Quirk 2010), which reiterates the need for baseload in the generation mixes of Figure 9 while the screening curves suggest it could be replaced by wind.

Suppose the amount $q^{\mathrm{B}}q^0$ of thermal baseload capacity is removed or simply made unavailable for some periods because wind is introduced into the grid. Then whenever wind power output is less than $q^{\mathrm{B}}q^0$, the supply curves in Figure 14 will shift to the left, thereby increasing market price; when wind power output increases to $q^{\mathrm{B}}q^0$, say, price falls. Thus, the effect of wind energy is to increase price volatility if there is insufficient thermal baseload available in the system; on the other hand, if thermal baseload capacity continues to be relied upon, electricity spot prices will generally be lower, but baseload plants will if possible need to ramp up or down more often if wind energy is non-dispatchable, which will increase their operating costs. Alternatively, if wind is considered dispatchable, wind energy output will need to be curtailed or wasted.

The presence of wind generating capacity also affects the reserve market. When wind enters the grid, there is a real risk that wind-generated electricity falls or rises dramatically and unexpectedly during the course of an hour. This means that the system operator must not only meet the reserve requirements of the regulatory authority, but also have additional contingent reserves to address the variability in wind. In the market for contingent reserves this is illustrated by the shift of demand from $\mathrm{D^C}$ to $\mathrm{D^{CW}}$ in Figure 15. Indeed, contingency reserves might need to increase by upwards of 10% and regulating reserves even more so, increasing the payment that an ISO has to pay for standby reserves.

The presence of significant hydro storage capacity enables a system to absorb wind power that might overwhelm a system with a large amount of thermal capacity in the generating mix, or raise system costs by too much in doing so. That is, the existence of hydro reservoirs enables a system to store wind energy that would be wasted in systems lacking hydraulic storage capacity. The stored wind energy can be used to meet demand at other times, perhaps during periods of peak load. This is true of other forms of storage as well, such as batteries, flywheels, et cetera. Unfortunately, outside of hydraulics, there is currently no inexpensive storage capacity available; however, even if adequate storage is available, it might favor thermal generation over wind as indicated in the next section.

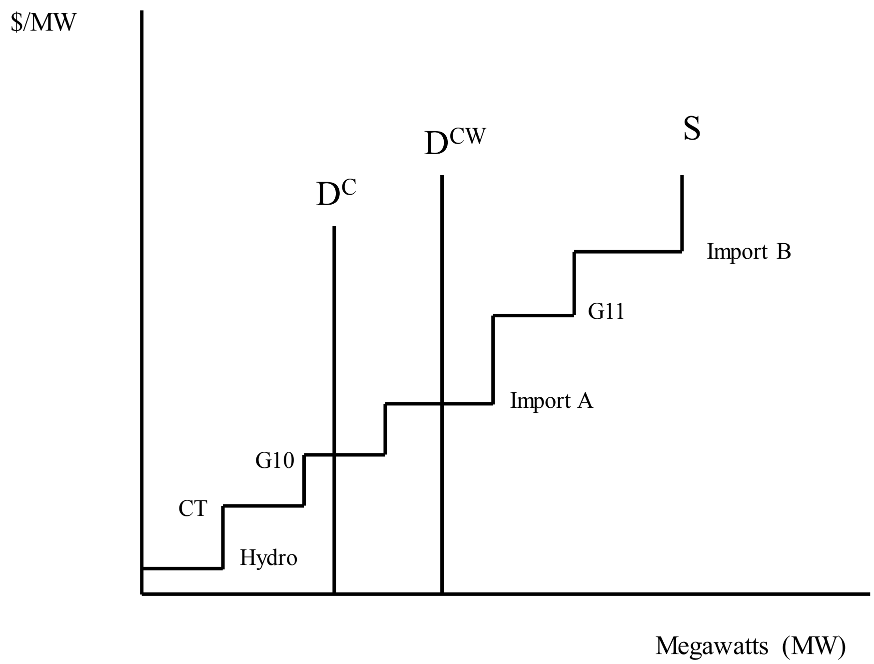

Figure 15: Impact of Wind Power on the Market for Contingent Reserves

Managing Electricity Systems with Intermittent Wind Power: A Review

The electrical load that the system operator must satisfy varies a great deal throughout the day and year. Power demand at night is some 50% to 80% below daytime peak demand, while peak winter or summer demands can challenge a system's overall capacity to provide power. In most jurisdictions, baseload demands are met by combined-cycle gas, coal or nuclear power plants. Because it is difficult and costly to adjust output from these baseload plants over short periods, it is necessary at peak demand times to have generation sources (e.g., open-cycle gas plants, hydroelectricity) that can rapidly adjust output, or the ability immediately to access electricity from another jurisdiction via a high-voltage transmission intertie.

Empirical studies indicate that the supply structure has implications for a system's ability to absorb renewable power from intermittent sources such as wind turbines (e.g., Hirst and Hild 2004; Lund 2005; Kennedy 2005; van Kooten 2010, 2012a; Kaffine et al. 2013). Research indicates that the wind blows frequently at night when demand is met by baseload plants. At that point in the demand cycle, price is often below the marginal cost of production and, because wind power enters the grid, the system operator must take some generating facilities off-line. Due primarily to cost considerations (including ramping rates and the high costs of operating at less than optimal capacity), system operators try to reduce the outputs of baseload plants as little as possible and such plants are rarely taken off line (Nordel's Grid Group 2000; Lund 2005; Scorah et al. 2012). Yet, the system needs to shed production. Of course, the best option would be to store excess electricity in a hydropower reservoir (Benitez et al. 2008; Scorah et al. 2012).

In the absence of storage, the successful integration of electricity from renewable sources depends on the legislation under which a system operator functions. If the operator is able to dispatch wind and other variable sources of power, costs will be much lower than if renewable energy is non-dispatchable – that it must be accepted regardless of the impact on other generating facilities. A number of studies have investigated the problems associated with non-dispatchable wind in systems where there are combined heat and power (CHP) facilities (Liik et al. 2003; White 2004; Lund 2005; NordREG 2014). Since heat is generally required at night, CHP facilities produce more electricity at night in competition with baseload power plants and wind energy. In this case, electricity grids are especially difficult to manage when nighttime output from large-scale wind farms approaches capacity and load is minimal, while output from baseload facilities remains high. Unless electricity can be 'dumped' into another jurisdiction during these times, the adjustment costs imposed on extant generators might be large.

It was for this reason that the Alberta Electrical System Operator, for example, agreed to massive expansion of wind generating capacity in the province with the proviso that wind output could be adjusted as needed to maintain grid reliability – renewable energy would be allowed to go to 'waste'. However, the AESO (2010-2013) is also exploring centralized wind power forecasts, a market for ramping (load-following) services, penalties and other instruments for better integrating variable wind into the grid (see also NERC 2009). Clearly, successful integration of wind energy depends on the generating mix of the existing system (Maddaloni et al. 2008a, 2008b; Prescott and van Kooten 2009).

The penetration of intermittent sources of power into an electrical grid has an impact on system CO_2 emissions that varies by generation mix (e.g., see Table 6 above) and by the hour of the day when wind replaces emissions from the marginal generator. If demand is high, the marginal generator is likely a combustion turbine gas plant, while, if demand is low, the marginal generator might be a coal plant. Thus, wind could offset more of CO_2 at night when the marginal generator is a coal unit than during the day when it is a gas unit (see Cullen 2013; Novan 2015).

Studies find that, if a coal-fired power plant needs to lower output to accommodate wind, this leads to inefficiencies in fuel use resulting from operating below optimal capacity. Storage of wind-generated electricity offers a way out – storage can absorb excess wind power and permit thermal plants to continue operating efficiently, thereby saving fuel and potentially reducing CO_2 emissions. This is already happening. For example, during the night Denmark sells excessive wind and CHP generated electricity to Norway and Sweden at low or even negative prices, importing high-priced hydro and nuclear power during daytime peak periods from these respective countries; however, the bulk of the trade is in a northerly direction (NordREg 2014).[33] Likewise, Alberta sells coal-fired and wind-generated power to BC, while Ontario sells nuclear energy to Quebec, along maybe with some coal/biomass and wind power. Both BC and Quebec have significant reservoir capacity that enables them to purchase cheap electricity from their neighbors at night, while selling back hydroelectricity at peak times during the day – *de facto* storage. Lack of intertie transmission capacity is the primary obstacle to greater profiteering from such exchanges (Gross et al. 2003, 2007; DeCarolis and Keith 2006).

It is clear that there are benefits from more closely linking disparate operating systems. It remains an empirical question as to whether the benefits of such links exceed the costs of building the required transmission infrastructure (Hughes and Brown 1995; Gagnon et al. 2002). Further, it is questionable whether it is worthwhile spreading wind farms over a large landscape and linking various wind-power producing regions with high-voltage, high-capacity transmission lines to reduce intermittency. As noted earlier, studies of Europe and Australia indicate that, even when wind farms are scattered across a vast landscape, there is no guarantee that wind output from different sites is sufficiently uncorrelated at all times to guarantee adequate production when it is required. Oswald et al. (2008) discovered that there were times when all of Europe's wind turbines essentially stood still for an extended period of time, while Miskelly (2012) found that the outputs of wind farms scattered across a vast area of Australia were highly correlated, and that there were many times when no wind power was available. These and other studies found that more wind power capacity and higher capacity interties could not guarantee sufficient

[33] Wind power production in Denmark fluctuates widely, from 0% to 132% of the electricity consumption in 2014 (ENERGINET.DK 2015); net exports of electricity to Norway and Sweden were 3.52 TWh in 2011 and 12.15 TWh in 2012, but it was a net importer of 0.58 TWh in 2013 (NordREG 2014). In 2014, 39.1% of Danish electricity consumption came from wind, but Denmark had to export 29.0% of its electricity to other Nordic countries and imported 37.5% of its consumption, indicating that it is dependent on non-wind (nuclear and hydro) power generated elsewhere. Because Germany increasingly needs to export excess wind to Nordic countries as well, Denmark is looking to new transmission Interties to the Netherlands and the UK (ENERGINET.DK 2015). However, to the extent that wind output is correlated across northern Europe, export prices will fall and may become negative (Hoskins 2015). For perspectives on the Scandinavian electricity sector and wind energy, see Söderholm et al. (2007), Pettersson and Söderholm (2009), and Pettersson et al. (2010).

wind power over a long enough period to serve as baseload capacity. Nonetheless, the issue of storage and geography warrants further investigation.

One interesting comparison pits wind against nuclear power. In a study of Ontario's power system, Fox (2011) used the screening curve approach to find the optimal generation mix from the load duration curve and the energy options available (e.g., hydro potential, coal and gas deposits, wind sites). He used a carbon tax to promote clean energy. Nuclear power bested wind as the tax rose because wind energy was considered to be too variable, the capacity factors for Ontario wind farms was too low, and, importantly, too much additional reserve capacity was needed relative to nuclear power. Coal did not enter the optimal generation mix, however, although additional investments in gas, hydropower and nuclear energy were chosen.

A similar result was obtained by van Kooten et al. (2013) for the Alberta system as configured in 2010. In contrast to Fox, these authors began with the existing generation mix, which included 350 wind turbines with a rated capacity of 805 MW. In 2010, the Alberta load averaged 8,188 MW, with peak load equal to 10,227 MW and minimum (or base) load of 6,524 MW. A unique feature of the Alberta grid was a 650 MW transmission intertie into British Columbia's hydroelectric system, which could store intermittent wind power. Indeed, prior to Alberta's investment in wind power capacity, the intertie was used to level output from Alberta's baseload coal plants – to keep the coal plants from ramping up and down too rapidly. British Columbia would purchase low-priced electricity at night when demand in Alberta was low, selling hydropower to Alberta during peak daytime hours.[34]

The authors imposed a cost for removing assets and an annualized fixed cost for adding new capacity that varied by generation type. A mathematical programming model was used to determine the optimal allocation of the 2010 load among generating assets, with wind treated as must run using actual 2010 wind-generated output. When no nuclear power is allowed in the mix, it is optimal to invest in new wind resources once the carbon tax reaches \$50/tCO_2, although coal assets are not shed until the price reaches \$75/tCO_2. Yet, even when the tax reaches \$150/tCO_2, one-third of the original coal-fired capacity is retained for baseload purposes, despite the installation of 19,750 MW of wind capacity. Further, along with the added wind capacity comes a 20% increase in gas plant generating capacity, which is required to backstop variable wind.

When nuclear power is permitted into the generation mix, it begins to enter at \$25/tCO_2; by the time the carbon price reaches \$75/tCO_2 all coal assets are shed, and gas plant capacity is halved (while initial wind capacity remains unchanged). The reason why nuclear is able to out-compete

[34] In 2014, BC exported 1.19 TWh of electricity to Alberta but imported only 0.47 TWh from Alberta (http://transmission.bchydro.com/transmission_system/balancing_authority_load_data/historical_transmission_data.htm [accessed July 9, 2015]).

wind despite the high costs of nuclear is due to the usual factors, but most importantly it is due to the high cost of backup gas plant capacity that accompanies wind and is unnecessary in the case of nuclear power. Further, the ability to store unneeded power at any given time via the Alberta-BC transmission intertie facilitates the operation of nuclear power plants so that optimal capacity exceeds baseload requirements – that is, nuclear power outbids wind in its ability to employ the hydro reservoir storage asset.

Table 10: Total Emissions under Various Scenarios and Carbon Taxes, Mt CO_2, Alberta Electricity Grid with Transmission Connection to Hydro Storage in British Columbia[a]

	No Trade		Low intertie capacity		High intertie capacity	
Carbon tax	Wind Only	Wind & Nuclear	Wind Only	Wind & Nuclear	Wind Only	Wind & Nuclear
$0	47.1	47.1	45.1	45.1	49.4	49.4
$25	30.6	30.6	32.0	32.0	34.4	34.4
$50	29.6	29.6	31.3	31.3	34.0	34.0
$100	29.4	29.4	28.9	28.9	30.9	30.9
$125	29.4	20.6	27.5	14.6	26.0	15.4
$150	24.8	7.0	19.2	3.9	16.4	3.7
$200	21.2	3.9	17.7	2.1	15.5	1.7

[a] Scenarios refer to AB-BC intertie capacities of zero MW (no trade), 650 MW and 1300 MW, while 'wind only' permits decommissioning and investment in thermal power plants and wind, and 'wind & nuclear' adds to this the ability to invest in nuclear power.
Source: van Kooten (2012b); van Kooten et al. (2013)

All of these factors affect the extent to which CO_2 emissions are reduced, as shown in Table 10. With no incentive to address climate change, an increase in the intertie capacity results in greater CO_2 emissions in Alberta as more electricity is generated from inexpensive coal, because coal power can be generated even during nighttime periods of low demand as it can be stored in BC for use the next day. When the carbon tax is \$100/tCO_2, there is a 36-37% reduction in CO_2 emissions as coal-fired power is reduced, regardless of whether investments in nuclear are permitted. However, at carbon taxes of \$125/tCO_2 or more, the ability to include nuclear power into the generating mix substantially reduces CO_2 emissions compared to a situation where the operator relies only on wind energy as a clean source of electricity. Once the carbon tax reaches \$200/tCO_2 significant nuclear capacity gets built; in that case, CO_2 emissions can be reduced by some 95% using nuclear assets compared to less than 70% by relying on wind. Clearly, wind alone will not enable an electricity system to meet a targeted emissions reduction of 80% or more. Likewise, Long and Greenblatt (2012) find that, for California, greater efficiency and large-scale investment in renewables (including wind, solar, biomass and geothermal) can possibly reduce CO_2 emissions by 60%. However, to go from a 60% reduction to 80% will require more radical solutions, including the deployment of nuclear power.

7. Policy Instruments to Support Wind Energy

Many countries have developed strategies to encourage wind power development to address their commitments to control CO_2 emissions. As of early 2015, at least 164 countries had renewable energy targets and some 145 countries had renewable energy support policies in place (REN21 2015, p.18).[35] The targets vary significantly across countries. Scotland, New Zealand and Germany have set targets to supply 100%, 90% and 80%, respectively, of their total electricity demand through renewable sources. The U.S. recently announced that 28% of electricity would be supplied by renewable energy by 2030, and 29 states, the District of Columbia and two territories have a Renewable Portfolio Standard (RPS) or mandate, while eight states and two territories have renewable energy goals (Simmons et al. 2015, p.13). Other countries have renewable energy targets that vary between 2% and 50% of electricity production, but over a period that might extend to 2030. The main policy instruments countries employ include feed-in tariffs (FITs), capital subsidies, tax incentives, tradable renewable energy certificates, mandatory targets, RPSs, priority in dispatching with guarantees to access transmission lines, and long-term contracts.

Among policy instruments, FITs that oblige electricity utilities to buy electricity generated from renewable sources at above-market rates are the most common. Most developed and some developing countries have implemented FITs for wind energy, with tariffs normally set for a specified period of five to twenty years. In Europe, FITs vary between €0.033/kWh in Denmark to €0.097/kWh in Austria. In India, the majority of the states have started feed-in tariff schemes to support wind energy.

In the U.S., the Production Tax Credit (PTC) along with an Investment Tax Credit (ITC) are the main vehicles for incentivizing wind production at the federal level. The PTC was set at $23/MWh in 2013, while the ITC amounts to 30% of fixed costs for eligible investments (e.g., grid-level wind farms are excluded). These incentives are estimated to provide a post-tax subsidy of $38/MWh (Simmons et al. 2015, p.6). The PTC is similar to a FIT and, since 2009, has cost taxpayers more than $5 billion annually and is projected to cost some $13 billion annually within a decade; yet the PTC accounts for less than 40% of total subsidies to wind (ibid., pp.8-10).

Individual states also provide a variety of tax incentives, particularly exclusion of renewable energy structures from the valuation of property for taxation purposes, plus state-level renewable portfolio standards to promote wind production. Sixteen of the 29 states with RPSs offer wind energy producers a renewable energy credit (REC) for each MWh of electricity they generate. These RECs can be sold in voluntary or mandatory markets to be purchased by fossil fuel

[35] Countries normally have targets for renewable energy as a whole, aiming to promote all possible sources of renewable energy instead of a particular one. The policy instruments are, in general, common to all renewable energy sources. More details are found in REN21 (2015).

generating assets that fail to meet their RPS (Novan 2015, p.295). Solar energy producers are often provided two RECs for each MWh of power. Not surprisingly, research indicates that the cost of electricity is 38% higher in states with a RPS (Simmons et al. 2015, p.13). Yet, investments in wind energy are highly sensitive to the PTC and not so much to state level incentives.

The Canadian province of Ontario has, arguably, the most lucrative FIT scheme in the world. Onshore wind farms receive 13.8 ¢/kWh, while offshore producers receive 19.0 ¢/kWh; what is more important is that the rate is indexed to inflation for a period of 20 years.[36] This contrasts with the approach in Alberta where the wholesale market is deregulated and there are no subsidies (and wind generating capacity has expanded significantly although returns might be negative, as discussed in section 6) and British Columbia where long-term contracts are employed (and much less wind power has come on stream).

In addition to the U.S. states, Australia, Japan and some European countries have introduced tradable Renewable Energy Certificates (tRECs) to promote all forms of renewable energy. Power companies can purchase tRECs to meet their renewable energy targets. The advantage of such certificates is that renewable power does not necessarily have to be delivered, thereby avoiding transmission constraints. For example, a jurisdiction that generated wind or hydro power can sell tRECs to another jurisdiction, thereby incurring an increase in associated CO_2 emissions. This works well if both jurisdictions have targets to reduce CO_2, but could potentially be open to corruption as the region selling tRECs could fail to claim a warranted increase in its own CO_2 emissions that does not show up when emissions are based on fossil fuel accounting (van Kooten and de Vries 2013). Nonetheless, by buying these certificates, consumers could help increase production of green power irrespective of the production location (US EPA 2008).

Using U.S. state level data for 1998 to 2007, Hitaj (2013) finds that subsidies, tax credits and policies that facilitate transmission access to the grid are effective means to promote wind power developments. Upon comparing policies, she finds that federal and state production incentives are 2.5 times more cost-effective than tax credits and other incentives.

In Germany, feed-in tariffs differ depending on a wind farm's location, with less favorable areas receiving higher subsidies. Differentiated pricing has not only been successful in incentivizing investment in wind turbines in less desirable locations. Using German county-level data for 1996-2010, Hitaj et al. (2014) find that the differentiated FITs, or feed-in premiums, have increased wind generated output by 1% and reduced CO_2 emissions by 3.7% per euro spent compared to a uniform incentive. They also find that the feed-in premiums program has been very effective with a €0.01/kWh increase in the subsidy leading to an average annual increase in

[36] For a discussion of global FIT programs and a cost-benefit analysis of the Ontario program, see van Kooten (2013b).

installed capacity of 765 MW for the entire study period, but 1,528 MW per year during the latter part, 2005 through 2010.

The selection of policy instruments is greatly influenced by national conditions, with most countries having introduced more than one policy instrument. Nonetheless, wind power continues to make only a small contribution to the global electricity supply mix (see Table 1 and Figure 2). Since wind power is more capital intensive compared to conventional fossil-fuel fired generating technologies, the relatively high capital costs continue to be an obstacle to the adoption of wind power at the scale supported by its potential. As the empirical examples of the previous section indicate, even when a carbon tax is used to penalize fossil fuels for their externalities, wind cannot compete because of its intermittency and need for reliable backup generation. While storage and adequate transmission capacity can be used to counter intermittency (Figure 5) and make wind energy more reliable, storage also makes investments in baseload capacity much more attractive, especially nuclear power but also CC gas technologies.

Wind Power and International Climate Change Initiatives

Many climate change initiatives have promoted wind energy over the past two decades, both in developed and developing countries. In the developed countries, fiscal policies and regulatory mandates enacted to meet Kyoto commitments have promoted wind power. In the developing countries, Kyoto's Clean Development Mechanism has played an important role, as indicated in Table 11. Various international organizations, particularly the World Bank and the United Nations, have also contributed significantly to the financing of wind power projects through the Global Environmental Facility.

Many developed countries have set targets for developing wind power as part of their overall renewable energy targets (RETs). In choosing targets and policies, countries take into account their climate change mitigation obligations as well as other considerations, such as long-term energy security. Australia had planned to install 10 GW of wind power capacity by 2020; the Canadian Maritime Provinces intended to install 1.2 GW of wind capacity by 2015; Spain hoped to reach 35 GW of wind capacity, including 3 GW of offshore wind by 2020; Egypt planned to have 7.2 GW of capacity operational by 2020; Algeria intended to reach 2.0 GW of capacity by 2020; and many other countries were intending to add more wind capacity, constrained only by their budgets. More recent developments in preparation for the Paris Conference of the Parties to the UN FCCC indicate that, if an agreement is reached, both developed and developing countries would need to revisit their commitments, if any, to wind power.

For developing countries, the CDM has played an instrumental role incentivizing wind power projects. By May, 2015, 2,628 wind power projects with a combined capacity of 120,751 MW were registered under the CDM. While these projects are distributed across the globe, 89% of the total projects constituting 82% of total capacity are concentrated in China and India. China alone accounts for about 70% of total installed capacity. Mexico, Brazil and Chile account for 43% of the remaining projects.

Table 11: CDM wind projects as of May 1, 2015

Country	Projects	MW	Country	Projects	MW
China	1,522	84,232	Egypt	4	406
India	830	14,517	Serbia	4	450
Mexico	30	4,276	Peru	4	233
Brazil	68	5,519	Ecuador	3	24
Chile	19	1,653	Israel	2	34
Uruguay	15	707	Azerbaijan	2	98
South Africa	16	2,451	Jamaica	2	39
South Korea	13	377	Tunisia	2	224
Argentina	11	665	Macedonia	2	137
Morocco	7	603	Guatemala	2	69
Dominican Republic	6	230	Honduras	2	152
Pakistan	8	405	Mongolia	1	50
Costa Rica	6	197	Senegal	1	125
Cyprus	6	268	Columbia	1	20
Philippines	5	321	Angola	1	100
Panama	5	674	Montenegro	1	46
Kenya	5	527	Cape Verde	1	26
Vietnam	5	188	Mauritius	1	18
Sri Lanka	5	51	Iran	1	100
Thailand	3	267	Sudan	1	100
Nicaragua	4	147	United Arab Emirates	1	25
TOTAL	**2,628**	**120,751**			

Source: http://www.cdmpipeline.org/cdm-projects-type.htm [accessed May 15, 2015]

While wind power projects account for approximately 30% of the total CDM projects registered or in the pipeline as of May, 2015, they accounted for only 10% of the certified emission reduction (CER) credits that were issued.[37] In addition to CDM projects, wind projects are constructed under Kyoto's joint implementation mechanism; between November 2006 and November 2013, wind farm developments account for 29 of 333 projects for which project design documents are available.[38]

[37] In contrast, projects to reduce hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulphur hexafluoride (SF_6) and nitrogen oxide (N_2O) account for 1.7% of projects but more than 50% of CERs issued. See http://www.cdmpipeline.org/cdm-projects-type.htm [accessed May 15, 2015].
[38] See http://ji.unfccc.int/JI_Projects/DeterAndVerif/Verification/PDD/index.html [accessed August 12, 2015].

8. Concluding Discussion

Mitigating climate change requires a reduction in the use of fossil fuels for generating electricity. Since nuclear power is not an option in many countries, wind energy is considered a logical alternative for generating power. In this paper, we investigated the economics of wind energy by first examining the costs and benefits of investing in wind capacity. Policymakers have implemented subsidies to promote wind energy based on the presumption that, because wind potentially displaces coal and other dirty fossil-fuel generated electricity, the social benefits of installing wind generating capacity will exceed the social costs. However, both econometric and mathematical programming studies suggest that this is not generally the case (e.g., Kaffine et al. 2013; Cullen 2013; Novan 2015; van Kooten 2010). Wind will substitute for power from the marginal generator at the time that the wind power enters the system. Because the marginal generator differs across generation mixes as well as with the time of day and by year, the extent to which carbon dioxide emissions are offset varies as well. Hence, more CO_2 emissions are avoided in systems that rely coal than those that rely more on gas, and hardly any CO_2 emissions are avoided when hydropower is the main energy source. Research concludes that subsidies for wind-generated power can only be justified if the generation mix has a great deal of coal.

The preferred alternative to subsidies is a carbon tax or carbon emission trading scheme. The carbon tax targets emissions from coal to a greater extent than those of gas, thereby incentivizing dismantling of coal plants, especially older and less efficient ones. A carbon emissions trading scheme will do the same, except that such a scheme is open to corruption (van Kooten 2015; van Kooten and de Vries 2013).

Econometric studies tend to neglect or underestimate the indirect costs of wind energy, which are associated with the impact that intermittent power has on the operation and management of an electricity grid. To gain a handle on these costs, it is necessary to understand how electricity systems operate – it is necessary to understand generation, transmission, distribution and consumption, and how each of these components can and should be deregulated, if at all. It turns out that the wholesale (generation) and retail markets can be deregulated, but that transmission and distribution are likely best left in the hands of an independent system operator, which also organizes the market and guides investment in new capacity (Joskow and Tirole 2006, 2007; Joskow 2012). While a carbon tax or emissions trading will eliminate coal from the optimal generation mix when wind enters, gas capacity will need to increase in order to backstop wind. Indeed, mathematical programming models indicate that the increase in gas capacity required is almost one-to-one for coal displaced. Researchers also identify problems associated with the inability to store wind energy (except behind hydroelectric dams), the need for fast-responding backup generating capacity, network instability, low capacity factors for wind power, et cetera, that could limit the penetration of intermittent sources of electricity. Overall, it may turn out that there are economic and physical limits to our ability to absorb additional wind and other intermittent energy.

For all of these reasons, researchers have concluded that wind energy has its limits. A sample of comments to this effect follow.

> "Wind assets … are being developed, but only because of a legal and political environment that provides lucrative subsidies and benefits to developers. Eventually these costs will find their way to the consumer, either through higher electricity prices or steeper taxes. The true cost of wind energy … is obscured by these massive subsidies, transmission projects that are difficult to factor into cost estimates, and threats to reliability created by flooding the energy market with underpriced wind power" (Simmons et al. 2015, p.24).

> "These findings concur with the empirical observations being made in both the UK and Germany, for example, where there is a new understanding, based on operational experience, that wind energy is both not decreasing CO2 emissions to any appreciable extent, but is also placing the continued operational security and reliability of those countries' respective grids under increasing strain" (Miskelly 2013).

> "Due to untimely changes and low availability of their fuels during hours of peak demand, wind and solar resources are not direct or complete substitutes for dispatchable resources. They are instead "supplemental" options that reduce the fuel consumption and utilization rates of 'dispatchable' units without replacing the need to build and maintain those units. Wind and solar therefore can be thought of as "energy only" resources that save a portion of the variable costs (fuel and variable operations and maintenance or O&M) but little or no fixed costs" (Stacy and Taylor 2015, pp.10-11).

Perhaps it is time to rethink society's commitment to wind energy. This is not to suggest that there is no role for wind. Rather, it is necessary to recognize the limits of wind energy and construct policies and electricity grids that recognize these limits.

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Appendix: Determining the Optimal Generation Mix

In this section, we provide an example of how to use screening curves in conjunction with the load duration curve to determine the optimal generation mix. The approach used here is similar to that of Joskow (2006) who, for illustration purposes, uses linear screening functions for three broad generation technologies and a linear load duration curve. We extend his approach to consider the case of a wind technology. The load duration curve is loosely based on Figure 6 for Ontario; it is given by the following equation:

(A1) $D(h) = 24{,}000 - 1.484\, h,\ 0 \leq h \leq 8760$

where D refers to the system load (MW), h is the number of hours the system load reaches that load and there are 8760 hours in the year.

The screening curves are provided in equation (3) in the text and repeated here. They have a fixed cost ($/MW) component, denoted *fc*, and a variable cost ($/MWh) component, denoted *vc*:

(A2) $C(h) = fc + vc \times h,$

where C refers to the total cost incurred to operate the asset for one year and h refers to the number of hours of electricity that the asset in question operates during the year. The fixed cost component consists of the overnight construction cost plus the fixed O&M costs, but then annualized. To calculate the fixed cost component and yet keep the example simple, we use the data from Table 4 as a guide and a discount rate of 10%. The screening curve data are provided in Table A1. The situation is illustrated in Figure A1.

Table A1: Assumed Values for the Screening Curves

Generation Technology	Annualized Capital Costs ($/MW per year)	Operating Costs ($/MWh)
Baseload	$200,000	$4.5
Intermediate/load following	$90,000	$26.0
Peaking	$55,000	$45.2
Wind	$240,00	$0.0

Source: Author's calculations

To determine the running time of each asset, we find the intersections of the screening curves for base and intermediate assets, and the intermediate and peaking assets. These values are provided in Figure A1 and Table A2. Finally, the optimal capacities of each asset type are then found from the load duration curve. These values are also provided in Figure A1 and Table A2. The fixed component of costs is simply given by the optimal capacity for the asset multiplied by the annualized capital cost. To determine the operating costs, we first find the megawatt hours that the asset is expected to operate during the year. This is given by the area underneath the load duration curve in the bottom panel of Figure A1. For baseload, it is given by area (a+b+c+d+e+f) and for the peaking asset by area k. This gives 133.881 TWh of baseload output during the year and 2.466 TWh of peaking output. The total cost of operating this hypothetical system for one year is about $5.025 billion.

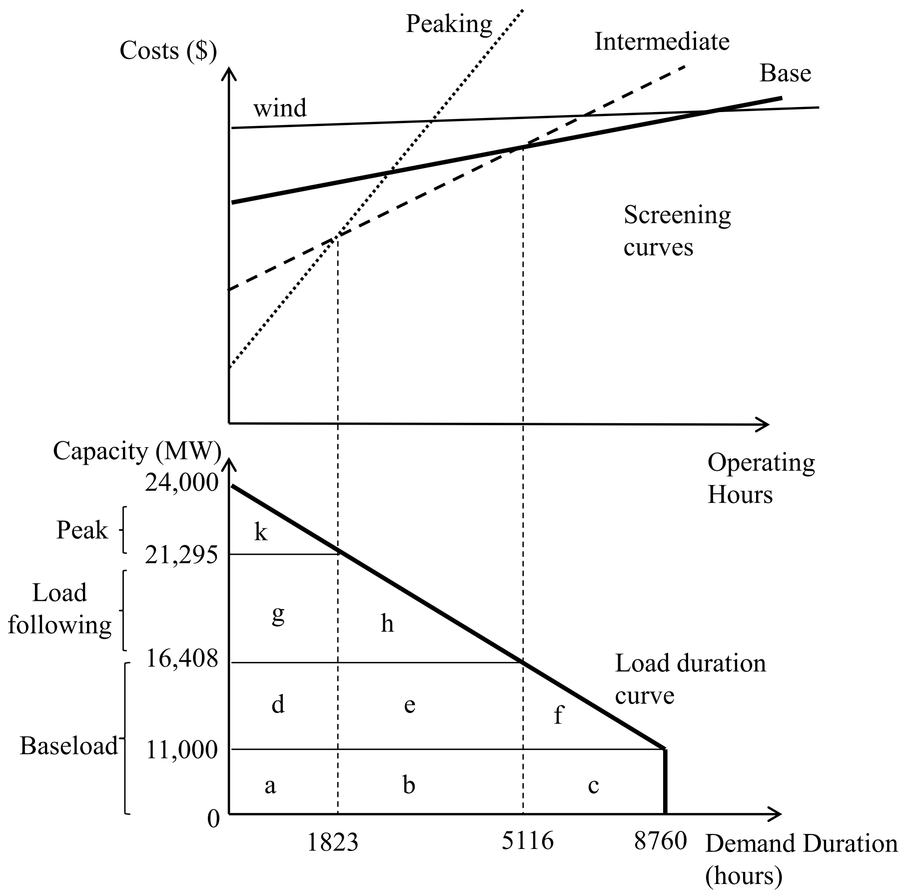

Figure A1: Determining the Least Cost Generating Mix

Table A2: Least Cost Mix of Generating Technologies, Running Times and Costs

Generation Technology	Capacity (MW)	Running hours[a]	Total Costs ($ billions) Fixed	Variable	TOTAL
Baseload	16,408	5116 – 8760	$3.282	$0.602	$3.884
Intermediate	4,887	1823 – 5116	$0.440	$0.441	$0.881
Peaking	2,705	1 – 1823	$0.149	$0.111	$0.260
Total	**24,000**	–	**$3.871**	**$1.154**	**$5.025**

[a] Hours not needed to service baseload (i.e., load following and peaking hours)
Source: Author's calculations

In the forgoing analysis, wind energy was too costly compared to the fossil fuel sources of energy. The picture changes, however, when governments intervene to discourage CO_2 emissions via a carbon tax or use a feed-in tariff to encourage investment in renewable resources, in this case wind generated electricity. The situation where a carbon tax is used in illustrated in

Figure A2, while that of a FIT is illustrated in Figure A3. We assume that peaking facilities emit 0.60 tonnes of CO_2 (tCO_2) per MWh, intermediate assets emit 0.45 tCO_2/MWh, and baseload plants emit 0.85 tCO_2/MWh. Then a \$30/tCO_2 carbon tax increases the operating costs of various technologies as indicated in Table A3. Using this information, we find that the least cost generating mix eliminates baseload (fossil fuel/coal) generating capacity. However, given the unreliability of wind energy, it is not possible to replace baseload capacity with wind. From Figure A2, it would be prudent to continue using the baseload facility with wind providing load following services. Even then, as noted in the text, it would be necessary to increase reserve capacity to backstop wind resources.

Table A3: Assumed Values for the Screening Curves under a Carbon Tax

Generation Technology	Annualized Capital Costs ($/MW per year)	Operating Costs including tax ($/MWh)
Baseload	$200,000	$30.0
Intermediate/load following	$90,000	$39.5
Peaking	$55,000	$63.2
Wind	$240,00	$0.0

Source: Author's calculations

We can also calculate the costs associated with the least cost generating mix in the case of a carbon tax. This is done in Table A4 using the same method as in Table A2. The costs of operating the minimum cost technology mix now come to $7.751, of which $2.653 billion is a transfer from fossil fuel producers and ultimately ratepayers to the government as a tax. Not surprisingly, the annual operating costs are now $5.142 billion, some $117 million greater than the $5.025 billion that it would have cost to produce the same amount of electricity in the absence of government intervention.

Table A4: Least Cost Mix of Generating Technologies, Running Times and Costs

Generation Technology	Capacity (MW)	Running hours[a]	Total Costs ($ billions) Fixed	Variable	Tax	TOTAL
Baseload	11,000	0	$2.200	$0.434	$2.457	$5.091
Intermediate	3,443	1477 – 3797	$0.310	$0.236	$0.123	$0.669
Peaking	2,192	1 – 1477	$0.121	$0.073	$0.029	$0.223
Wind	7,365	3797 – 8760	$1.768	$0.000	$0.000	$1.768
Total	**24,000**	–	**$4.399**	**$0.743**	**$2.653**	**$7.751**

[a] Not including any hours needed to service baseload (i.e., load following and peaking hours)
Source: Author's calculations

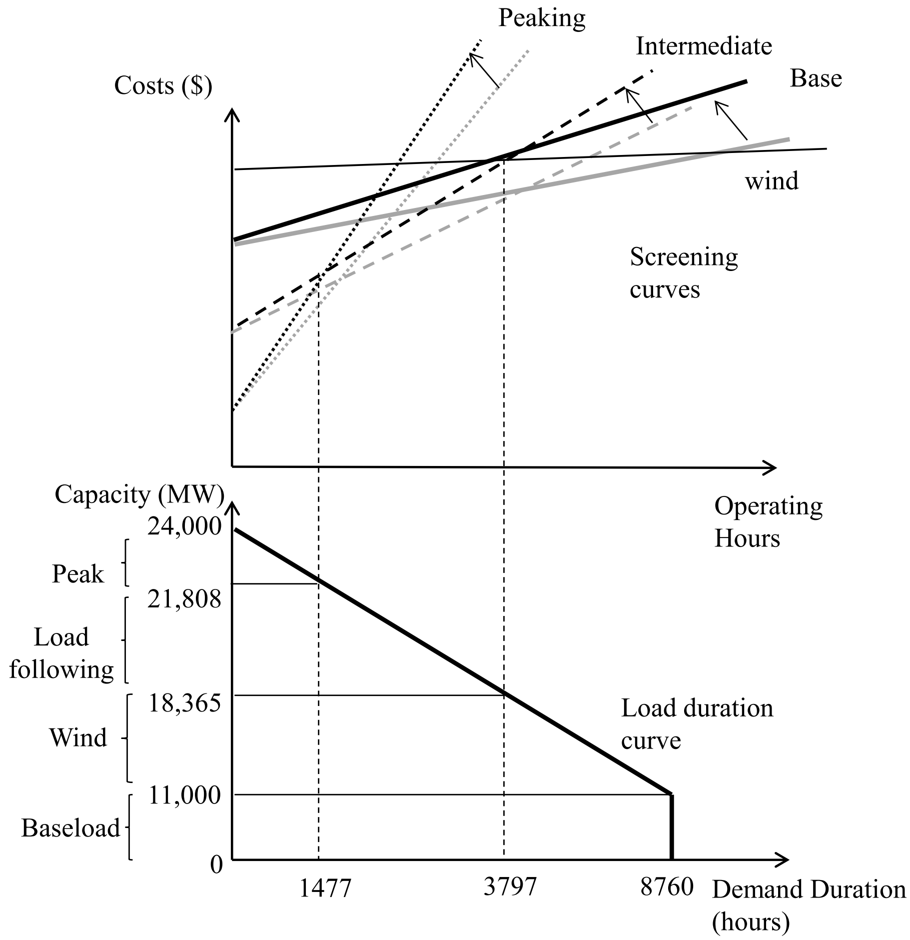

Figure A2: Least Cost Generating Mix under a Carbon Tax

Finally, consider the case of a feed-in tariff for wind energy. The FIT only affects the screening curve for wind energy but does not affect those of other generation technologies. Initially it was assumed that there was no variable cost to generate wind energy, which meant that the screening curve for wind was flat. With a FIT, the screening curve has a negative slope given by the difference between the FIT and the realized wholesale spot price in each hour. In practice, the subsidy ($/MWh) would vary but, given that screening curve - load duration method assumes demand is fixed in each hour (see text), we simply assume a fixed subsidy rate that gives us the same result as in the case of the carbon tax. The subsidy that results in this outcome is $13.505/MWh. The situation under a FIT is provided in Figure A3, while the associated least cost generation mix, running times and costs are given in Table A5.

The total cost of generation now equals $5.766 billion, of which $0.624 billion constitutes a subsidy paid either by taxpayers or ratepayers, or some combination. The true cost to society of meeting the annual load is again $5.142 billion – higher than the cost without government intervention. Because of subsidies, the generating sector only incurs costs of $4.518 billion.

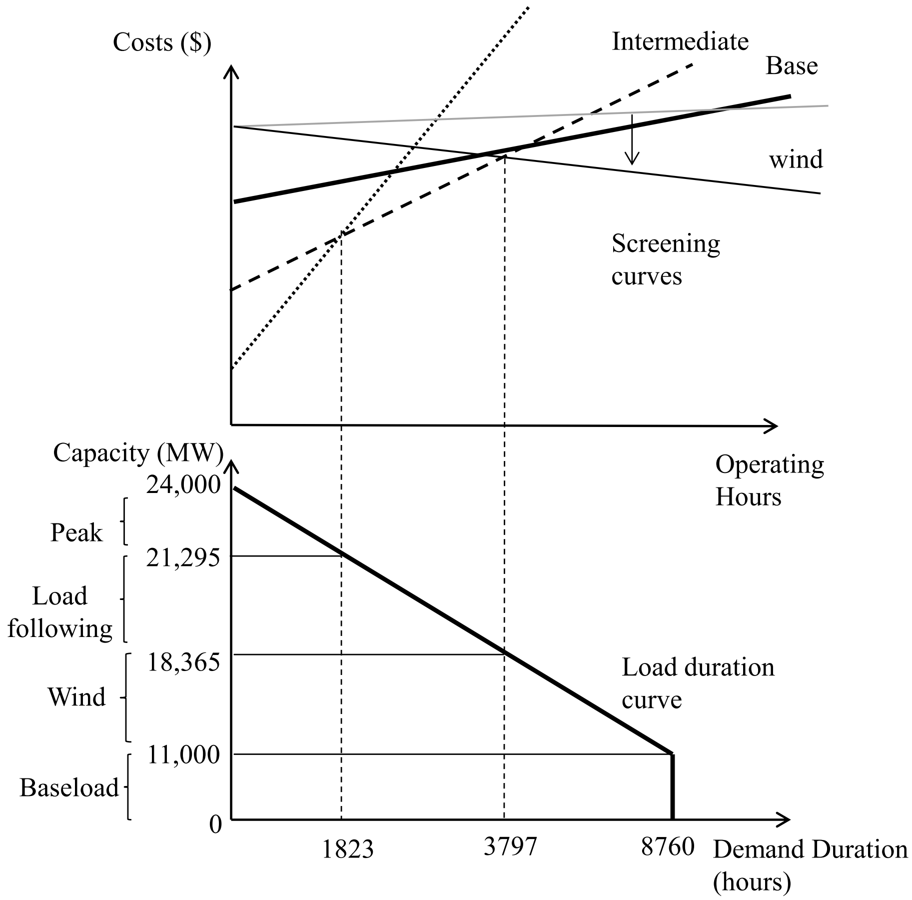

Figure A3: Least Cost Generating Mix under a Feed-in Tariff for Wind Energy

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Table A5: Least Cost Mix of Generating Technologies, Running Times and Costs

Generation Technology	Capacity (MW)	Running hours[a]	Total Costs ($ billions) Fixed	Variable	Subsidy[b]	TOTAL
Baseload	11,000	0	$2.200	$0.434	n.a.	$2.634
Intermediate	3,443	1477 – 3797	$0.310	$0.236	n.a.	$0.546
Peaking	2,192	1 – 1477	$0.121	$0.073	n.a.	$0.194
Wind	7,365	3797 – 8760	$1.768	$0.000	$0.624	$2.392
Total	**24,000**	–	**$4.399**	**$0.743**	**$0.624**	**$5.766**

[a] Not including any hours needed to service baseload (i.e., load following and peaking hours)
[b] n.a. = not applicable
Source: Author's calculations