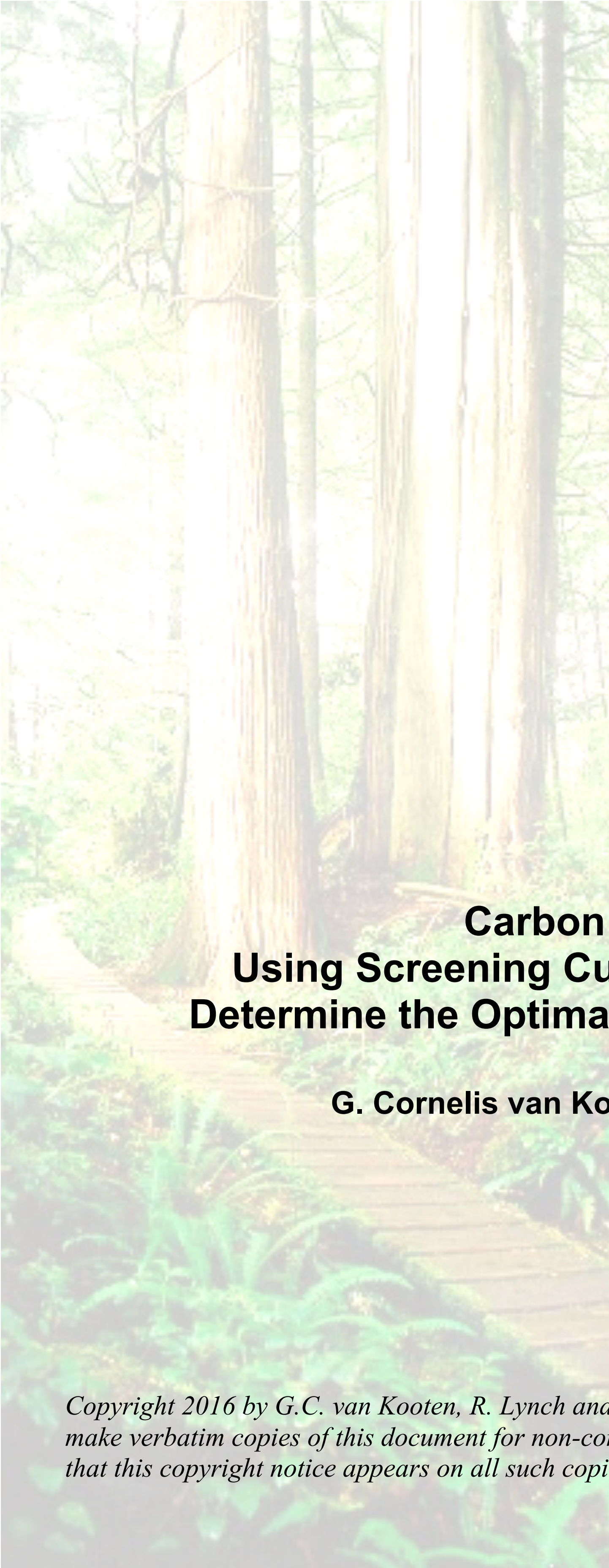

WORKING PAPER 2016-02

REPA

Resource Economics & Policy Analysis Research Group

Department of Economics University of Victoria

Carbon Taxes and Feed-in Tariffs: Using Screening Curves and Load Duration to Determine the Optimal Mix of Generation Assets

G. Cornelis van Kooten, Rachel Lynch and Jon Duan

June 2016

Copyright 2016 by G.C. van Kooten, R. Lynch and J. Duan. All rights reserved. Readers may make verbatim copies of this document for non-commercial purposes by any means, provided that this copyright notice appears on all such copies.

For copies of this or other REPA working papers contact:

REPA Research Group
Department of Economics
University of Victoria PO Box 1700 STN CSC Victoria, BC V8W 2Y2 CANADA
repa@uvic.ca
Fax: 250.721.6214
http://web.uvic.ca/~repa/

This working paper is made available by the Resource Economics and Policy Analysis (REPA) Research Group at the University of Victoria. REPA working papers have not been peer reviewed and contain preliminary research findings. They shall not be cited without the expressed written consent of the author(s).

Carbon Taxes and Feed-in Tariffs: Using Screening Curves and Load Duration to Determine the Optimal Mix of Generation Assets

G. Cornelis van Kooten, Rachel Lynch and Jon Duan
Department of Economics, University of Victoria

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 study, we discuss how screening curves and load duration can be used to determine the optimal investment in generating assets, and extend this method to include wind and nuclear energy sources. We then use this approach to investigate the effects of carbon taxes and feed-in tariffs (FITs) on the optimal generation mix and the potential for reducing CO_2 emissions. We find that a carbon tax is likely more effective than a feed-in tariff for removing fossil fuel assets and incentivizing investment in wind power. The tax leads to the removal of coal-fired capacity that is replaced by combined-cycle gas generation. However, if nuclear energy is permitted to enter the mix, the tax results in coal capacity replaced by nuclear power instead of gas, which leads to a significant reduction in greenhouse gas emissions compared to any other alternative considered. We also find that, because wind cannot substitute for baseload generation, the additional investment in wind resulting from a carbon tax or FIT is small compared to the absence of any incentives (only 7%). Finally, if the tax and FIT lead to the same mix of generating assets, the income distributional effects can be quite large. It is the distributional effects of policy, and associated rent seeking activities to implement a FIT, that could be the deciding factor in choosing between a carbon tax and feed-in tariff.

Key Words: Electricity; renewable energy and climate change policy; wind power; nuclear energy

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

Acknowledgement: The author wishes to acknowledge funding from NSERC's Discovery Grants program and the Canada Research Chair program.

1. Introduction

At COP-21 in Paris in December 2015, Canada stated that it "intends to achieve an economy-wide target to reduce our greenhouse gas emissions by 30% below 2005 levels by 2030." One of its strategies for achieving this target is to ban construction of new coal-fired power plants and phase out existing ones. Federal government regulations would require 12 of 18 of Alberta's coal plants to close by 2030, but the province intends to close all coal plants by 2030 (Henton and Varcoe 2015; Government of Canada 2011). The Alberta government is hoping to replace two-thirds of coal-fired electricity with renewables, primarily wind, with renewable energy sources accounting for 30% of electricity production by 2030. To that end, the province is also implementing a carbon tax that is to start at \$20/tCO_2 in 2017 and rise to \$30/tCO_2 in 2018 (Government of Alberta 2015).

Most jurisdictions have turned to wind energy for meeting CO_2-emission reduction targets. However, there are a number of problems with wind power that could limit its usefulness at higher penetration rates. These include the inability to store intermittent wind energy (except behind hydroelectric dams), the need for fast-responding backup generating capacity, and low capacity factors.[1] Nonetheless, studies find that, when allowance is made for the negative externalities associated with fossil fuel burning, the benefits of wind exceed their costs, thus justifying public intervention via taxes or subsidies. The question is whether wind can contribute much towards meeting the more stringent targets set out in Paris.

In this paper, the economics of wind energy are investigated by examining its role in the optimal mix of generating assets. Specifically, we examine how government policy can affect the extent of wind power in the optimal mix of generation assets. In particular, we study the impact of carbon taxes and feed-in tariffs (FITs) on wind power using the framework of a load duration curve (demand) and screening curves (supply) (Stoft 2002). The main ingredients in this framework are hourly load and the fixed and variable costs of generating electricity from various energy sources. The framework of analysis, load data and cost information are discussed in section 2.

The load duration and screening curves are used to guide grid operators, investors and policy makers in making optimal investments in generating capacity. Such investment decisions are impacted by carbon taxes and feed-in tariffs. In section 3, we examine how a carbon tax and FITs affect investment decisions, and the costs and income distributional impacts of policy choices. Finally, in section 4, we apply this approach to examine optimal investments in wind energy in Alberta, determining the outcomes associated with a carbon tax versus a FIT for

[1] A generating asset's capacity factor is given by the ratio of the annual power generated by the asset divided by its capacity multiplied by 8760 hours (8784 hours in a leap year).

incentivizing investment in wind power generation. Wind power data and other information are available from van Kooten et al. (2016).

The social benefits and costs of wind power, including both direct and indirect aspects, are evaluated by analyzing data in terms of more comprehensive measurements, such as the levelized costs of electricity (LCOE), spot prices for electricity, and requirements for storage or natural gas assets as backup. Using the benefit and cost data, the impact of carbon taxes and feed-in tariffs on wind power are studied using the load-duration-screening-curve framework. The results show that wind should be chosen to provide baseload and much load-following capacity. However, wind energy is too unreliable to be used for baseload capacity; a system without nuclear assets should optimally still rely on coal to provide reliable baseload capacity. Given the variability of wind output, it will be necessary to backstop wind by investing in additional gas capacity as reserve.

2. Framework for Determining Optimal Investment in Electricity Grids

In this section, we provide a framework that uses screening curves in conjunction with the system's load duration curve to determine the optimal generation mix. The approach used here is similar to that of Joskow (2006, 2011) who uses linear screening functions for three broad generation technologies and a linear load duration curve (see Stoft 2002). We extend his approach to consider the potential to invest in wind technologies. The load duration curve is found by assembling the hourly loads in order from highest to lowest. An example of a load duration curve is provided in Figure 1 for Alberta, where, in 2014, the maximum load in any hour was 11,169 MW while the smallest load was 7,162 MW. This meant that a baseload power facility (a group of baseload plants) could continuously generate 7,162 MW without having to ramp production up or down. Compared to other electricity grids, however, the Alberta grid is characterized by a high baseload relative to its peak load, with baseload accounting for 78.4% of total demand. This is primarily due to the high industrial demand for power relative to other jurisdictions, and the use of natural gas rather than electricity for space heating.

For the analysis that follows, we employ a linear load duration curve that is loosely based on 2008 data for Ontario. For Ontario in 2008, the peak load was nearly 24,000 MW (which occurred in June when power was needed for cooling and not heating[2]) and average baseload during the year close to 11,000 MW (accounting for 68% of total annual demand). The linear representation of the load duration curve is given by:

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

[2] In contrast, the winter peak load exceeded the summer peak load in Ontario in 2014.

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

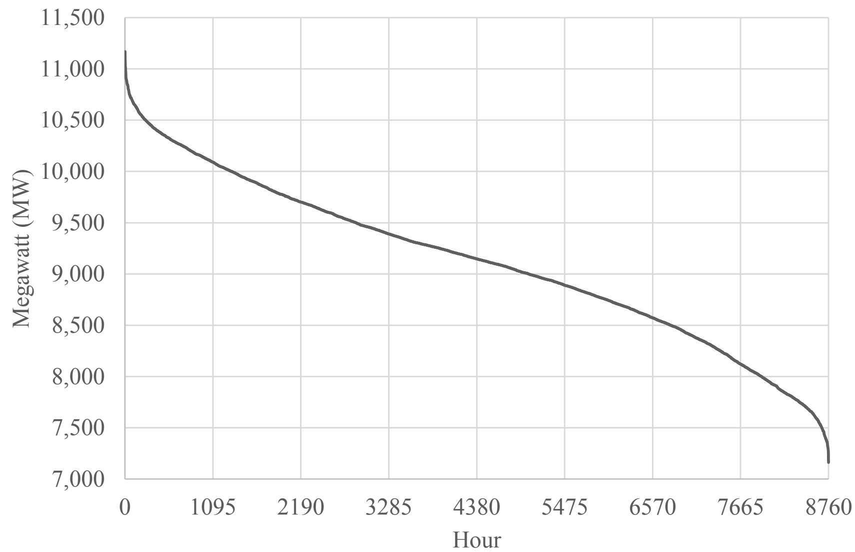

Figure 1: Load Duration Curve, Alberta, 2014

Screening curves have a fixed cost ($/MW) component, denoted *fc*, and a variable cost ($/MWh) component, denoted *vc*:

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

where C refers to the total cost of operating 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 annualized overnight construction cost plus the annual fixed operating and maintenance (O&M) costs. The problem is to determine the costs of generating electricity.

To find the costs of producing electricity from various technologies, two concepts are important: the overnight construction cost and the levelized cost of electricity (LCOE). The overnight construction cost ($/MW) 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; it ignores financing costs (i.e., interest rates) as it is assumed that the generating facility is literally built overnight. The levelized costs include the capital costs, operating and maintenance (O&M) costs (including replacement of capital items as a result of wear and tear), 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.

A summary analysis of the components constituting the LCOE is provided in Table 1 for seven technologies – two wind technologies, solar, natural gas, coal, hydro and nuclear. The analysis is most sensitive to the overnight construction cost and assumed capacity factors (CFs). Thus, maximum and minimum values are provided, with average LCOE values provided in Figure 2. The lowest costs of generating electricity occur with combined-cycle (CC) gas plants, followed by hydroelectricity (but not run-of-river) assets, and coal plants (Table 1). The overall average ranking in Figure 2 of different generating technologies clearly indicates that, based solely on capital and operating costs, fossil fuel generation is clearly the least expensive option. 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 fossil fuels to clean technologies.

To calculate the fixed cost component and yet keep the example simple, we use the data from Table 1 as a guide and a discount rate of 10%. The screening curve data are provided in the two middle columns of Table 2. The situation is illustrated in Figure 3. To determine the running time of each asset, we find where the screening curves for base and intermediate assets intersect, and where those of the intermediate and peaking assets intersect. Finally, the optimal capacities of each asset type are then found from the load duration curve in the manner shown in the figure. Results are provided in Table 3 and Figure 3 itself.

Table 1: 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
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 (2010), Timilsina et al. (2013), and authors' calculations.

Table 2: Assumed Values for Screening Curves, with and without Carbon Tax

Generation Technology	Annualized Capital Costs ($/MW per year)	Operating Costs: Base ($/MWh)	Operating Costs: $30/tCO$_2$ tax ($/MWh)
Baseload	$200,000	$4.5	$30.0
Intermediate/load following	$90,000	$26.0	$39.5
Peaking	$55,000	$45.2	$63.2
Wind	$240,000	$0.0	$0.0

Source: Authors' calculations.

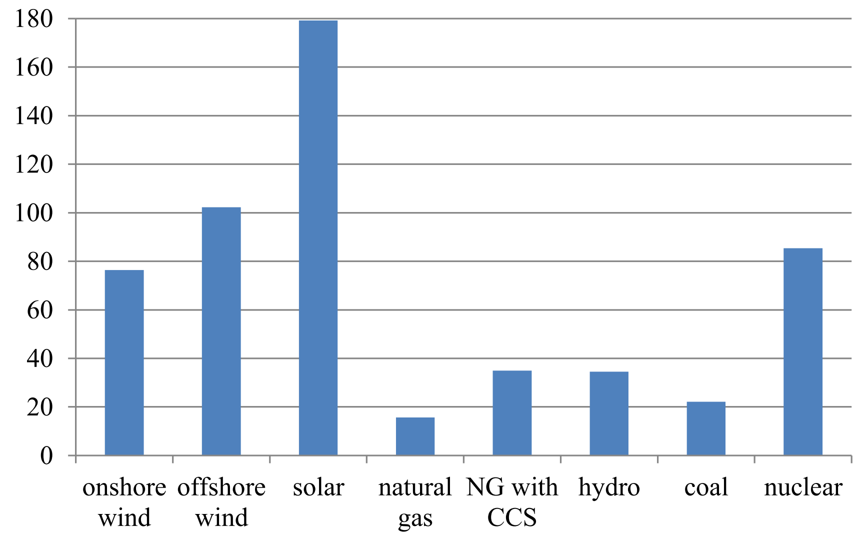

Figure 2: Levelized cost of producing electricity with indicated technologies, US$ per MWh

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 3. For baseload plants, it is given by area (a+b+c+d+e+f), even though the baseload is only area (a+b+c), and for the peaking asset by area k. This gives 133.881 TWh of production by baseload plants 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.

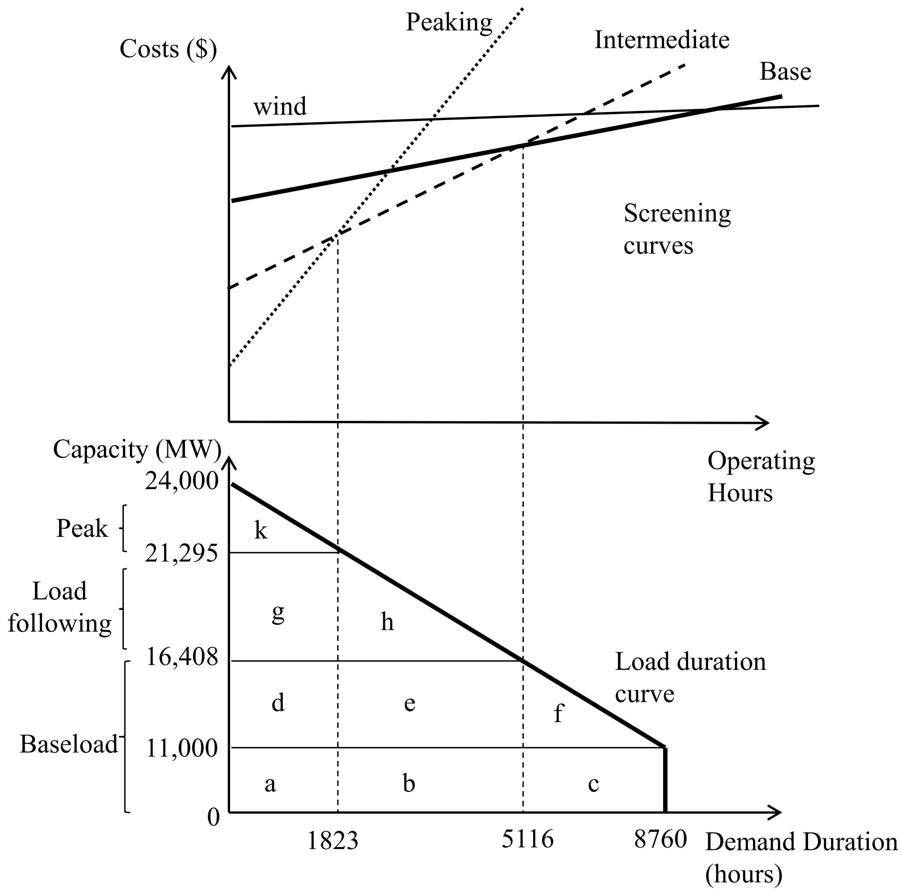

Figure 3: Determining the Least Cost Generating Mix

Table 3: 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: Authors' 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 is illustrated in Figure 4, while that of a FIT is illustrated in Figure 5. 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 the last column of Table 2. 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 3, it would be prudent to continue using the baseload facility with wind providing load following services. Even then, it would be necessary to increase reserve capacity to backstop wind resources.

Using the load-duration-screening approach, we also calculate the costs associated with the least cost generating mix in the case of a carbon tax. The results are provided in Table 4. The costs of operating the optimal 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 4: Least Cost Mix of Generating Technologies, Running Times and Costs under a Carbon Tax of $30/tCO$_2$

Generation	Capacity	Running	Total Costs ($ billions)			
Technology	(MW)	hours[a]	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: Authors' calculations

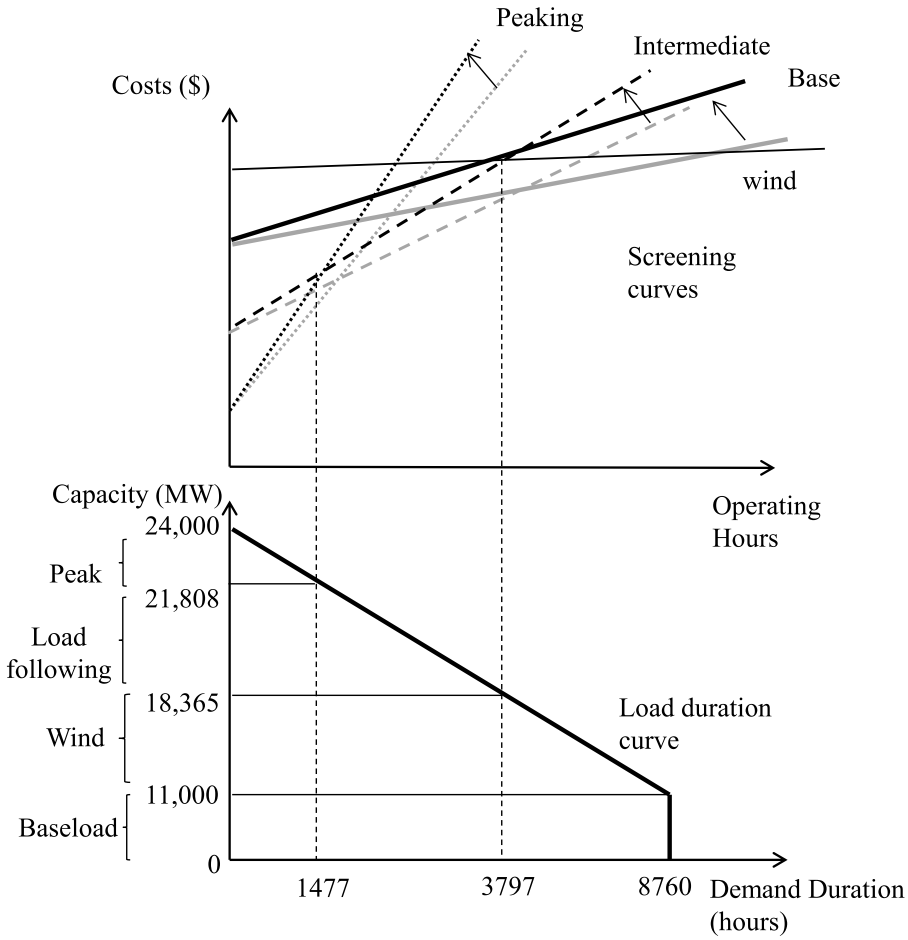

Figure 4: Least Cost Generating Mix under a Carbon Tax

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 the load-duration-screening method assumes demand is fixed in each hour, we simply assume a fixed subsidy rate that gives us the same result as with the carbon tax. The required subsidy is $13.505/MWh. The situation under a FIT is provided in Figure 4, while the associated least cost generation mix, running times and costs are provided in Table 5.

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.

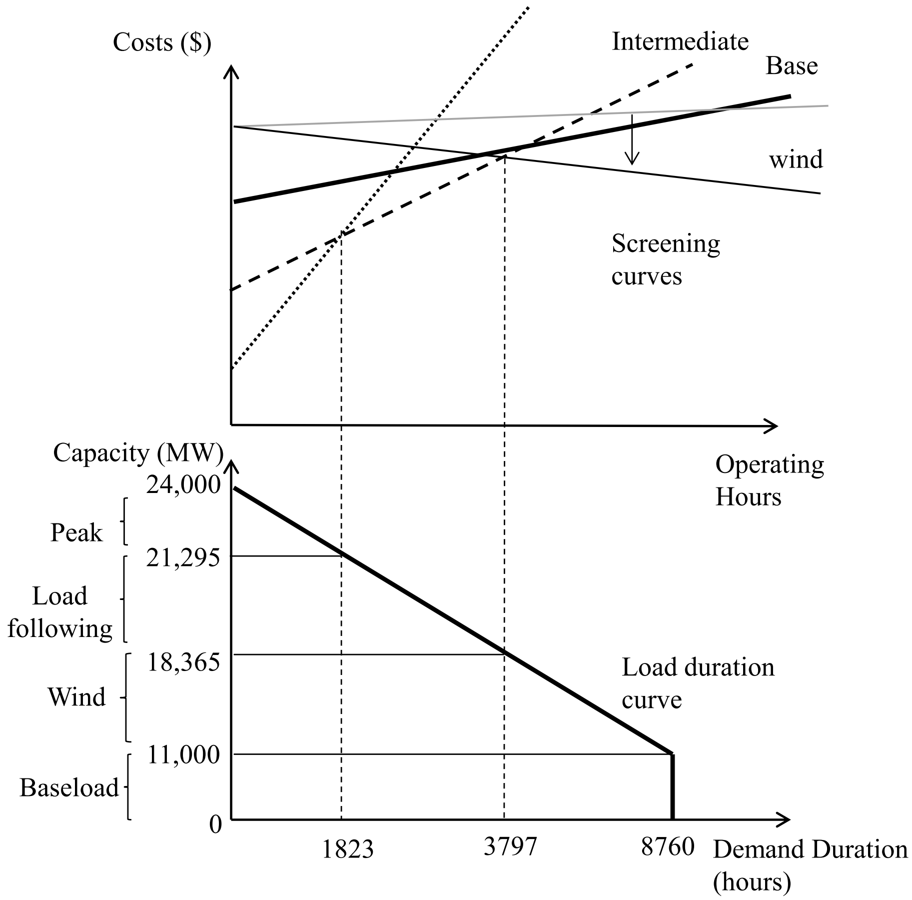

Figure 5: Least Cost Generating Mix under a Feed-in Tariff for Wind Energy

Table 5: Least Cost Mix of Generating Technologies, Running Times and Costs under a Feed-in Tariff

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	1823 – 3797	$0.310	$0.236	n.a.	$0.546
Peaking	2,192	1 – 1823	$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: Authors' calculations

3. An Application to Alberta

Since Alberta is implementing a carbon tax and seeking to eliminate coal-fired power, in this section we examine the performance of a carbon tax relative to a feed-in tariff for Alberta using the load-duration-screening method. We also consider what might happen if nuclear power were permitted into the generation mix, because nuclear power is one option for reducing CO_2 emissions associated with the oil sands, thus making such oil more palatable in export markets, especially the U.S. Alberta's current generation mix and actual generation in 2014 are provided in Table 6.

Table 6: Alberta Generation Mix by Fuel Source, Capacity (2015) and Actual Generation (2014)

	Capacity		Generation	
Fuel Source	MW	Proportion	GWh	Proportion
Coal	6,258	38.5%	44,442	55.0%
Natural Gas	7,080	43.6%	28,136	35.0%
Hydro	900	5.5%	1,861	2.0%
Wind	1,459	9.0%	3,471	4.0%
Biomass	447	2.8%	2,060	3.0%
Other[a]	98	0.6%	373	0.0%
TOTAL	**16,242**	**100.0%**	**80,343**	**100.0%**

[a] Other includes fuel oil and waste heat generation, which produces electricity from a heat source that is a by-product of an existing industrial process whose heat that would have otherwise been wasted.
Source: http://www.energy.alberta.ca/Electricity/682.asp

The Alberta load duration curve for 2014 is provided in Figure 1, while the values for the screening curves that are used in this analysis are provided in Table 7. In the base case, there is no intervention to incentivize clean energy, while in the other two scenarios we consider a carbon tax of \$30/tCO_2 and, as an alternative, a feed-in tariff of \$20.317/MWh for wind energy that leads to the same optimal wind capacity. The optimal generation mixes, the number of hours per year they operate, and total system costs are provided in Tables 8 through 11 for the base case, carbon tax, carbon tax plus nuclear option, and FIT scenarios, respectively.

In the base case, not surprisingly, coal dominates with gas CC and, to a much lesser extent, gas GT active in providing load following and peaking services. As a baseload facility, gas CC plants are more flexible and able to respond somewhat faster to changes in load than coal plants. The total cost of meeting Alberta's 2014 load is \$4.254 billion (Table 8). In the least cost generating mix, all technologies (except nuclear) enter the optimal mix of assets to provide electricity to Alberta. The baseload in this scenario is composed of coal, because of its low operating costs (Table 7). The costs of operating peak gas facilities are low because they operate for a limited number of hours (less than 120 hours per year) and little capacity is required. Wind power makes up about a quarter of the electricity provided in the optimal mix.

Table 7: Assumed Values for the Screening Curves, Base Case,

Generation Technology	Annualized Capital Costs ($/MW per year)	Operating Costs Base ($/MWh)	$30/tCO$_2$ tax ($/MWh)	$30/MWh FIT ($/MWh)
Coal	$151,523	$38.40	$66.75	$66.75
Gas CC	$110,728	$48.90	$69.15	$69.15
Gas GT	$104,080	$10.50	$127.50	$127.50
Wind	$191,572	$0.00	$0.00	$-20.32
Nuclear	$349,668	$29.60	$30.20	$30.20

Table 8: Least Cost Mix of Generating Technologies, Running Times and Costs for Alberta, No Carbon Tax or Feed-in Tariff

Generation Technology	Capacity (MW)	Running hours[a]	Total Costs ($ billions) Fixed	Variable	TOTAL[b]
Coal (baseload)	7,162	1-8760	$1.085	$2.409	$3.494
Gas CC	691	119-1652	$0.077	$0.052	$0.129
Gas GT	54	1-119	$0.006	$0.000	$0.006
Wind	3,262	1652-8760	$0.625	$0.000	$0.625
Total	**11,169**	–	**$1.792**	**$2.461**	**$4.253**

[a] Except for baseload which runs the entire time (1-8760 hours), these refer to hours a generating asset operates but not to service baseload.
[b] Totals may not add due to rounding.
Source: Authors' calculations

Now consider a $30/tCO$_2$ carbon tax as proposed by the Alberta government. As indicated in Table 9, the tax drives coal out of the generating mix, replacing baseload generation with gas CC, increasing the amount of gas CC capacity as load following and leaving peak gas capacity effectively unchanged at slightly more than 50 MW. More importantly, the carbon tax will incentivize investment in wind capacity, which increases by almost 220 MW. The cost to society of generating the electricity needed to satisfy the load increases from $4.253 billion in the base case to $4.610 billion, or by $357 million, because the tax distorts the allocation of load to generators (i.e., mainly shifting generation from coal to natural gas). The tax revenue amounts to $1.897 billion so that the cost to owners of generators effectively increases from $4.253 billion to $6.608 billion. To the extent that power producers can shift costs to customers, ratepayers might well have to pay the extra $2.355 billion that it costs to produce electricity in the form of higher prices, although the rate would increase by less than 1¢ per kWh. The high variability of wind patterns means, however, that it cannot be relied upon to cover the baseload power needed to generate electricity.

Table 9: Least Cost Mix of Generating Technologies, Running Times and Costs under a Carbon Tax of \$30/tCO$_2$, Alberta[a]

Generation Technology	Capacity (MW)	Running hours	Total Costs ($ billions) Fixed	Variable	Tax	TOTAL
Gas CC (baseload)	7,638	1-8760 & 114-1169	$0.846	$3.093	$1.897	$5.835
Gas GT	51	1-114	$0.005	$0.000	$0.000	$0.006
Wind	3,480	1169-8760	$0.667	$0.000	$0.000	$0.667
Total	**11,169**	–	**$1.518**	**$3.093**	**$1.897**	**$6.508**

[a] See notes on Table 8.
Source: Authors' calculations

Now consider a \$30/tCO$_2$ carbon tax but permit investment in nuclear capacity in addition to coal, gas and wind. The results are provided in Table 10. As before, the tax drives out coal generating capacity but now also drives out baseload gas CC, leaving non-baseload gas CC and peak gas capacity effectively unchanged (from Table 9) at 476 MW and 51 MW, respectively. Baseload gas CC is eliminated as nuclear replaces it as the low-cost baseload generator because nuclear emits no CO_2 and therefore does not need to pay the carbon tax. When nuclear power enters the (optimal) generation mix, fixed costs are higher, and variable costs and the tax revenue are much lower.[3] However, ignoring income transfers and the benefits of reduced CO_2 emissions (which are substantial as indicated by the low revenue from the carbon tax), the cost to society has increased from \$4.253 billion in the base case to \$5.164 billion in this case, or by \$911 million. It is a political decision whether this sacrifice is worth the benefit.

Table 10: Least Cost Mix of Generating Technologies, Running Times and Costs under a Carbon Tax of \$30/tCO$_2$, Alberta[a]

Generation Technology	Capacity (MW)	Running hours	Total Costs ($ billions) Fixed	Variable	Tax	TOTAL
Wind	3,480	1169-8760	$0.667	$0.000	$0.000	$0.667
Gas CC	476	114-1169	$0.053	$0.026	$0.015	$0.092
Gas GT	51	1-114	$0.005	$0.000	$0.000	$0.006
Nuclear (baseload)	7,162	1-8760	$2.504	$1.857	$0.038	$4.361
Total	**11,169**	–	**$3.229**	**$1.882**	**$0.053**	**$5.164**

[a] See notes on Table 8.
Source: Authors' calculations

Finally, a feed-in tariff only affects the slope of the screening curve for wind. As a result, wind substitutes for some gas, but coal is chosen to provide baseload generation (which wind cannot provide due to its unreliability) simply because it is the lowest cost source of generation at the baseload scale. Meanwhile peak gas capacity and generation are essentially unaffected. That is,

[3] Emission reductions can be determined by dividing the total tax revenue by \$30/tCO$_2$.

some gas GT and gas CC are required to satisfy peak load and some load following needs, but the system continues to be dominated by coal unless other steps (carbon tax, regulation) are taken to remove coal capacity. The total cost to society in this scenario is $4.783 billion, or $530 million. This is nearly equal to the amount that the annual government subsidy to the wind power producers ($537 million). The FIT subsidies incentivize the removal of some gas capacity, but do not greatly enhance the capacity or amount of wind generation.

Table 11: Least Cost Mix of Generating Technologies, Running Times and Costs under a Feed-in Tariff, Alberta

Generation	Capacity	Running	Total Costs ($ billions)			
Technology	(MW)	hours	Fixed	Variable	Subsidy	TOTAL
Coal (baseload)	7,162	1-8760	$1.085	$2.409	n.a.	$3.494
Gas CC	472	118-1,295	$0.052	$0.027	n.a.	$0.079
Gas GT	53	1-118	$0.006	$0.000	n.a.	$0.006
Wind	3,481	1,168-8,760	$0.667	$0.000	$0.537	$1.204
Total	**11,169**	–	**$1.810**	**$2.436**	**$0.537**	**$4.783**

[a] See notes on Table 8.
Source: Authors' calculations

4. Discussion

To determine the impact that intermittent power has on the operation and management of an electricity grid, it is necessary to understand factors that determine optimal investments in electricity grids. Access to natural resources affects the existing, presumably optimal mix of generating assets and thus the costs and benefits of generating electricity, and the ability of the grid to accommodate wind power. But policies that governments use to incentivize investments in generating assets are also important. A carbon tax incentivizes energy companies and grid operators to eliminate coal from the generating mix and, instead, invest in wind turbines. The feed-in tariff only incentivizes investment in wind turbines. We find that neither a carbon tax nor a FIT does much to increase wind generation capacity in Alberta, which is increased by only 7% over a base case scenario of no intervention – an increase in wind generating capacity of about 220 MW, or some 88 turbines with a capacity of 2.5 MW each. However, the carbon tax does eliminate coal-fired generating capacity, by encouraging a substitution to lower-emitting gas capacity, while the FIT retains coal capacity for baseload generation.

In judging between a carbon tax and a feed-in tariff, this study clearly comes out in support of the former. However, given the size of the tax revenues, it is important to determine how these revenues are recycled back into the economy. One method is to provide ratepayers lump-sum compensation for the higher prices of power, but it needs to be done in a way that encourages greater conservation. Otherwise, the added income could lead to increased consumption of energy intensive products, thereby offsetting some of the benefits of reducing emissions of CO_2

using this policy instrument. Likewise, if the government spends the tax in a way that increases energy consumption, the impact of the policy is dampened.

Finally, it could simply be that policies that aim to increase wind power are misguided and need to be rethought. Is wind power an effective means of meeting CO_2-emissions reduction targets? It is our contention that wind can be an effective means of reducing greenhouse gas emissions but that it is only one approach that should not be singled out. Rather, investment in wind energy should be seen as only one approach to reducing CO_2 emissions within the larger framework of a carbon tax. Certainly, our research indicates that feed-in tariffs to incentivize wind power should be removed from the policy arsenal.

References

EIA, 2010. Updated Capital Cost Estimates for Electricity Generation Plants. U.S. Energy Information Administration. http://www.eia.gov/oiaf/beck_plantcosts/index.html [accessed April 5, 2016].

Government of Alberta, 2015. Climate Leadership Plan will protect Albertans' health, environment and economy. November 22. http://www.alberta.ca/release.cfm?xID=38885E74F7B63-A62D-D1D2-E7BCF6A98D616C09 [accessed February 10, 2016].

Government of Canada, 2011. Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations, *Canada Gazette* Vol. 145, No. 35 (August 27, 2011).

Henton, D. and C. Varcoe, 2015. Early shutdown of coal-fired power plants could cost billions of dollars: analyst, *Calgary Herald*, November 25.

Joskow, P.L., 2011. Comparing the Costs of Intermittent and Dispatchable Generating Technologies, *American Economic Review, Papers and Proceedings* 101(3): 238-241.

Joskow, P.L., 2006. Competitive Electricity Markets and Investment in New Generating Capacity. CEEPR WP 06-009. Center for Energy and Environmental Policy Research, Department of Economics and Sloan Scholl of Management, MIT, Cambridge, MA. April 28. 74pp. http://dspace.mit.edu/bitstream/handle/1721.1/45055/2006-009.pdf?sequence=1 [accessed May 14, 2015].

Stoft, S., 2002. *Power System Economics. Designing Markets for Electricity*. Piscataway, NJ: IEEE Press/Wiley-InterScience.

Timilsina, G.R., G.C. van Kooten and P.A. Narbel, 2013. Global Wind Power Development: Economics and Policies, *Energy Policy* 61: 642-652.

van Kooten, G.C., R. Lynch and J. Duan, 2016. Should Albertans be a "big fan" of Wind Power? Contributed paper presented at the Joint Annual Meeting of the Canadian Agricultural Economics Society and Western Agricultural Economics Association, June 24-26, Victoria, BC.