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Optimal Environmental Policies and Renewable Energy Investment in Electricity Markets

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Optimal Environmental Policies and Renewable Energy Investment in Electricity Markets

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Abstract

Renewable electricity subsidies have been popular policy instruments to combat climate change because of their ability to offset emissions. This paper studies the long-run welfare benefits of optimizing the design of the existing renewable energy subsidy (the status quo) in the presence of heterogeneity in the offset emissions. In particular, I measure the welfare gain from differentiating renewable subsidies across *location* and *time* to reflect the environmental benefits from offseting emissions. I find that the welfare gain from differentiation is small compared to the gain already achieved under the status quo subsidy. In contrast, the optimal emissions tax yields much larger welfare gain because it engages in other cost-effective emissions abatement channels that renewable energy subsidies do not: namely, demand conservation and cross-plant fuel substitution.

Keywords: Climate Change, Renewable Energy, Emissions Tax, Renewable Subsidies, Electricity Market, Investment, Environmental Benefits, Marginal Emissions, Heterogeneity, Fuel Switching, Demand Response, Wind Resource

1. Introduction

The electricity generation sector is one of the largest greenhouse gas emitters (U.S. Environmental Protection Agency, 2013). Thus, it has been at the forefront of several climate change mitigation policies in recent years. Important supply-side regulations to reduce emissions from this sector include direct emissions pricing and indirect subsidies to renewable electricity production and investment.[1] Putting prices on emissions, either in the form of an emissions tax or emissions cap and trade program, is the most efficient policy in the sense that it achieves emissions reduction at the lowest cost. Emissions pricing achieves pollution

[1] There are also different measures on the demand side. These measures include electricity efficiency standards, real-time pricing, and demand response programs. The evaluation of these demand-side policies is beyond the scope of this paper. However, demand responses will be triggered indirectly through higher electricity prices as a result of the emissions tax.

abatement through several channels: (i) fuel switching in the short run, (ii) end-of-pipe pollution treatment in the short/medium run, (iii) demand conservation in the short run, and (iv) clean electricity capacity investment in the long run. Although putting price on emissions would achieve greater efficiency, such a policy has proven to be politically infeasible in most part of the United States.[2] As a result, renewable electricity subsidies have been more prevalent.[3]

Renewable electricity subsidies compensate renewable power for its ability to offset both the production and emissions from fossil-fueled power plants. The offset electricity production costs determine the *market value* of renewable electricity, which are reflected through electricity prices. The offset emissions define the external *environmental value* of renewable electricity, which is not internalized without proper government intervention. Together, the sum of the market value and environmental value constitutes the *social value* of renewable electricity (Borenstein, 2012). Despite growing interests in renewable electricity subsidies, there exists little quantitative work to assess how the optimal design of these subsidies are affected by the heterogeneity in the market and environmental values.

Within an electricity grid, the market and environmental values of renewable power exhibit both spatial and temporal heterogeneity. This is due to constraints imposed by the existing thermal generation mix, available renewable resources, transmissions grid, and locations of demand. In the presence of this heterogeneity, the effectiveness of renewable electricity subsidies depends on their ability to induce quantities and locations of renewable capacity investment that maximize social value. Theoretically, the optimal form of renewable electricity subsidies should be *variable* subsidies that are added to the market price. In other words, the rates should be differentiated across time and location, and equal to the

[2]To date, there are two programs in the United States that regulate and put prices on greenhouse gas emissions through cap-and-trade. First, the Regional Greenhouse Gas Initiative (RGGI) puts a cap (and price) on greenhouse gas emissions from the power sector in the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont since 2008. Second, the California's Global Warming Solutions Act of 2006 ("AB32"), which created a market for greenhouse gas trading in California starting in 2013. Outside of the United States, the European Union Emissions Trading System (EU ETS) is the largest emissions trading system in the world.

[3]Important forms of implicit and explicit renewable electricity subsidies include renewable portfolio standards (RPSs), clean electricity standards (CESs), feed-in-tariffs (FITs), and production tax credits (PTCs). RPSs and CESs require a proportion of electricity generation procured by a regulated entity to come from renewable sources (or in some case from cleaner non-renewable generation sources). They implicitly subsidize renewable sources while taxing thermal generation sources (Fischer, 2010). FITs lock in electricity rates paid to renewable generation sources. The FIT rates can either be specified in addition to the market price or as a fixed rate above the average market price. Lastly, PTCs provide a fixed subsidy per unit of renewable electricity generation. In this paper, I will consider all the above policies under the generic label, "renewable electricity subsidy," and explore how the design of this generic subsidy affects renewable capacity investment, the evolution of the electricity market, and corresponding welfare. When relevant, I will discuss the differences that could arise among these options.

environmental value of renewable electricity generation. In practice, one-size-fit-all *uniform* subsidies with undifferentiated rates have prevailed because of their simplicity. Moreover, the observed uniform subsidies are not necessarily set to reflect the environmental values of renewable electricity generation. I refer to these observed uniform subsidies as the status quo subsidies.

Recently, the idea of differentiating subsidies for renewable electricity based on environmental value has gained attention from scholars and policy makers. A growing list of studies have documented substantial variation in the environmental benefits of renewable electricity both within and across electricity markets (Novan, 2014; Cullen, 2013; Kaffine et al., 2012; Graff Zivin et al., 2014; Fell et al., 2012). This evidence has led scholars to believe that differentiating renewable subsidy rates across time and location could lead to a considerable welfare gain.

This paper evaluates the long-run welfare benefit of differentiating renewable subsidies across time and location to reflect the heterogeneity in the actual environmental values of wind power. I define this type of subsidy as the "optimal variable subsidies." To assess their benefits, I construct a realistic, yet computationally feasible, empirical model of an electricity market. The model simulates short-run electricity market operation and long-run wind capacity investment subject to the locations of wind resources, existing transmissions grid, and demand centers. I calibrate the model using data from the Texas electricity market (Electricity Reliability Council of Texas, or ERCOT). I then simulate the long-run electricity market equilibria with wind capacity investment and calculate the social welfare attained by the status quo and optimal variable subsidies. I compare the social welfare under the aforementioned policies to two useful benchmarks: the optimal emissions tax and the unregulated baseline. To my knowledge, this is one of the few empirical studies to model the competitive renewable capacity investment decisions and measure the relative performance of emissions pricing and various designs of renewable electricity subsidies in the presence of heterogeneous environmental and market values.

The electricity market model constructed in this paper shares many general features with those in Bushnell (2010), Allcott (2012), and Green (2007). It is arguably closest to the one in Fell and Linn (2013). Using data from ERCOT, Fell and Linn (2013) construct an electricity market model with generation capacity investments to assess the relative cost effectiveness of different environmental regulations. While the model in Fell and Linn (2013) presents a novel way to quantify the effects of different environmental policies in electricity markets, it is not suitable for studying the impact of heterogeneous environmental benefits. The major reason is that their model assumes away transmission constraints that limit electricity flows between subregions within a market. Without transmission constraints, the electricity grid operates as a single electricity market in each period. Renewable electricity generated from different locations would have the same environmental value because it would displace emissions from the same marginal thermal generator regardless of where it was produced. Therefore, the model is unable to capture spatial variation in the environmental benefits, which could be substantial for certain types of renewable electricity such as wind power (Callaway and Fowlie, 2009; Novan, 2014; Kaffine et al., 2012; Graff Zivin et al., 2014; Siler-Evans et al., 2013). My electricity market model incorporates transmission capacity as constraints in the optimization and thus allows me to explicitly calculate the market and environmental values of renewable generation across time and subregions within ERCOT. Thus the computation of market prices, subsidies, investment and welfare are all internally consistent within the model framework.

There are three major empirical results. First, there exists a substantial variation in the environmental benefits of wind generation across time and regions within the ERCOT market. Second, the optimal variable subsidies lead to a moderate welfare gain over the status quo uniform subsidy for the social cost of carbon between \$35 to \$50 per ton and a much smaller gain at high social cost of carbon. Despite a large spatial and temporal variation in the environmental benefits, most of the welfare gain from the optimal variable subsidies come from their ability to induce the optimal *level* of total investment, and not so much on their ability to coordinate the optimal *location* of investment. The limited gain from subsidy differentiation is due to the negative correlation between wind resource productivity and its environmental benefits. Differentiated subsidies shift new investments to areas with high environmental values. However, because these areas have less productive wind resource, they require more total investment to maintain the same level of wind output. This increases total investment cost and offsets the gain in environmental benefits.

Last, the optimal variable subsidies offer a welfare gain that is small compared to that from the optimal emissions tax. This occurs because the optimal emissions tax induces not only efficient level and location of renewable investment, but also the "low-hanging fruits" emissions abatements through demand reduction and cross-plant fuel substitution (e.g., coal versus natural gas). In fact, more than half of the welfare advantage of the optimal emissions tax comes from these last two channels. Together, the results from this study suggest much higher returns from policies that stimulate demand conservation and cross-plant fuel substitution than policies that induce efficient investment in renewable capacity.

This paper proceeds as follows. Section 2 provides institutional details of the ERCOT market. Section 3 lays out a two-stage theoretical model and characterizes the electricity market and investment equilibrium. A formal theoretical model for welfare comparison of different environmental policies is outlined in Section 4. Section 5 describes data and model calibration. Simulation results under each policy scenario are presented in Section 6. Section 7 presents additional sensitivity analyses. Last, Section 8 concludes.

2. Background

2.1. The Electricity Reliability Council of Texas (ERCOT)

The Electricity Reliability Council of Texas (ERCOT) is an independent entity that manages an electricity market that serves almost 23 million customers (almost 85 percent of electric load in Texas).[4] Until 2011, the ERCOT wholesale energy market consisted of day-ahead bilateral trades between generators and retailers and a real-time (balancing) energy market. The majority (95 percent) of electricity in ERCOT was transacted through bilateral contracts. The remaining 5 percent was sold through the real-time market, which is the main focus of this paper. The major roles of the real-time energy market include balancing energy demand and supply in real-time and managing electricity flows from one location to another in the market. Although the balancing energy market only accounts for a small portion of energy being traded in ERCOT, balancing energy prices play important roles in determining contract prices, real-time production, and investment decisions (Potomac Economics, 2008).

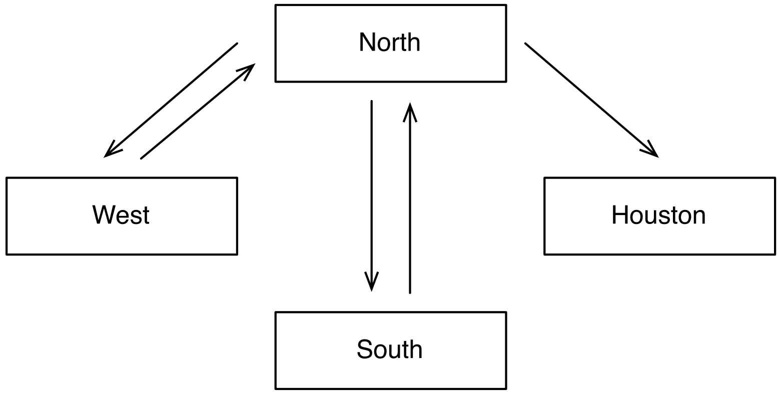
The majority of energy in ERCOT is generated from natural gas. A lesser fraction of energy comes from oil, coal, and nuclear. Wind power, which constitutes the largest share of renewable generation in ERCOT, accounts for 6 percent of the total energy being generated in 2009. In recent years, Texas has seen a robust growth in wind capacity investment, making ERCOT the nation's leader in renewable generation capacity (U.S. Energy Information Administration, 2014).

Before 2011, the ERCOT region was divided into four different geographical zones for congestion management: West, South, Houston, and North. Each congestion regions were linked to one another by generic transmission elements with limited transport capacity. Figure 1 displays the 4 congestion zones and 5 interzonal transmission elements linking them.

All the market participants in ERCOT (e.g. load-serving entities and generators) must be represented by the Qualified Scheduling Entities (QSEs). The QSEs receive demand forecasts and generator's real-time energy supply schedules from their market participants and submit these information to the system operator. At the beginning of each operating hour, the system operator gathers the most recent information from the QSEs and issues production instructions to individual generation units to minimize production costs of serving the ERCOT-wide energy demand. If these production instructions result in energy flows that

[4] http://www.ercot.com/

Figure 1: Schematic map of ERCOT 4 congestion zones and 5 interzonal transmission elements



exceed export or import capability of any transmission line, interzonal congestion occurs. The system operator will then reissue the "constrained" production instructions by allowing the maximum energy import or export in each zone to be equal to the transmission line capacities. This constrained production instructions involve curtailing low-cost generation in the export-constrained zone and increasing higher-cost generation in the import-constrained zone (relative to the unconstrained quantities). It also results in zone-specific energy prices that reflect the marginal costs of serving demand (net of import and export) within each congestion zone. In general, energy prices in an import-constrained zone will be higher than those of an export-constrained zone when transmission constraints bind.

Many characteristics render the ERCOT market in 2008 a suitable setting to study. First, ERCOT has experience with many existing supply-side environmental regulations. These regulations include a $23 per MWh Federal renewable production tax credit for the first 10 years, a renewable portfolio standard (RPS) with the goal of 10,000 MW by 2025, and tradable permits for NO_x and SO_2 for most parts of Texas (U.S. Department of Energy, 2013b). Second, due to its success in implementing renewable energy policies, Texas has the largest wind capacity installation in the U.S. In 2008, a rapid increase in wind energy penetration made the interzonal congestion much more frequent and accentuated the role of heterogeneity in the market and environmental values. Lastly, for historical reason, the ERCOT grid is isolated from other electricity grids. This structure allows me to abstract away from modeling power import/export and still not severely bias the estimates and simulation results.

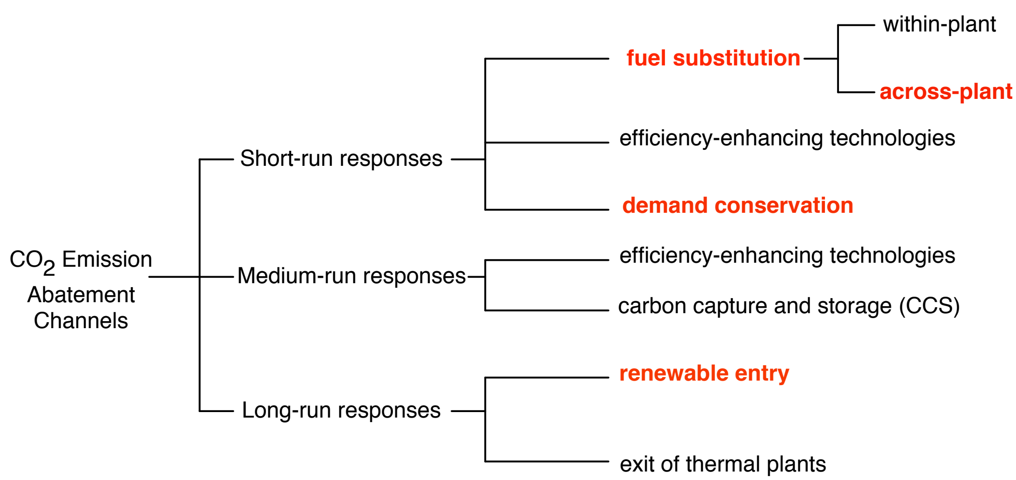
2.2. Emissions abatement channels

Environmental regulations in the electricity generation sector generally aim to target three major pollutants: carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides

(NO_x). Unlike CO_2, SO_2 and NO_x are non-uniformly mixed pollutants. Hence their marginal damages vary across locations and times (Fowlie and Muller, 2013). This makes evaluation of the external cost of SO_2 and NO_x quite problematic. Since both SO_2 and NO_x are already regulated in ERCOT as of 2008, this study will focus exclusively on the unpriced CO_2 emissions.[5]

This paper considers two generic supply-side CO_2 regulations: emissions pricing and renewable energy production subsidies. These policies could potentially trigger short-, medium-, and long-run emissions abatement through channels listed in figure 2.

Figure 2: Various emission abatement channels



The **short-run** abatement channels involve decisions made on an hourly or a daily basis. These decisions include (i) substitution toward cleaner fossil fuel and (ii) reduction in energy demand through higher energy prices. Fuel substitution can be further categorized into *within-plant* substitution and *cross-plant* substitution. Within-plant fuel substitution occurs when a plant with a particular technology (e.g. coal) substitutes toward a less emission intensive fuel (U.S. Environmental Protection Agency, 2010). Cross-plant fuel substitution occurs when the system operator substitutes away energy production from more emission-intensive plants toward less emission-intensive plants. This type of substitution is possible

[5]In theory, welfare gain from regulating CO_2 could be overstated if some of the CO_2 reduction in the model is caused by existing SO_2 and NO_x regulations. In reality, most power plants in ERCOT were already covered under the SO_2 and NO_x regulations prior to the study period. Thus, the marginal cost, emissions, and other plants characteristics used in the current study should already incorporate the impact of SO_2 and NO_x regulations on CO_2 emissions. Therefore, the CO_2 reduction benefit calculated here should only come from the new CO_2 regulations. On the other hand, if the new CO_2 regulations cause further reduction in SO_2 and NO_x emissions, the total welfare benefit of these new CO_2 regulations will be understated because they ignore benefits from additional SO_2 and NO_x reduction.

if the emissions tax sufficiently raises the plant's marginal cost and alters its position within the aggregate supply curve (U.S. Energy Information Administration, 2012).

The **medium-run** channels involve efficiency-improvement retrofits and carbon capture and storage (CCS) (U.S. Environmental Protection Agency, 2010). Efficiency-improvement retrofits increase fuel efficiency of the the existing generation units so that less fuel will be used and less CO_2 will be emitted for the same amount of electricity generated. Carbon capture and storage technology captures CO_2 that occurs during in the heat generation process and deposits it so that it does not enter the atmosphere.

Lastly, the **long-run** channels involve decisions made over a year or a longer time horizon. These decisions include investments in clean production technology and/or exits of dirtier thermal technology which could occur over the course of 4-5 years.

In this paper, I consider three channels of emissions abatement as highlighted in bold in figure 2. I abstract away from modeling within-plant fuel substitution as well as investment in efficiency-enhancing and CCS technologies for several reasons. First, modeling such decisions requires collecting detailed data on plant-level operations, fuel characteristics, and retrofit technologies, which is beyond the scope of this study. Second, the CCS technology is still costly and unlikely to soon become a dominant pollution abatement channel in the electricity generation sector (Ansolabehere, 2006). Since these channels are triggered mainly by emissions pricing, omitting these other abatement channels will cause the welfare benefit of emission pricing to be underestimated. Attending to these other channels would reinforce the key finding that the optimal emissions tax offers a substantially higher welfare gain than the optimal subsidies.

2.3. Heterogeneity in environmental benefits of renewable power

Renewable power has low marginal cost and low emissions. Therefore, it has the potential to displace output from the more expensive and dirtier thermal plants that are operating on the margin. Figure 3 illustrates how the displacement occurs. The upward-sloping dotted line denotes the aggregate supply curve for electricity in a particular hour. The red solid line denotes the marginal CO_2 emissions curve associated with this aggregate supply curve. Electricity demand is given by a vertical line. The short-run electricity market clearing occurs at the intersection between the aggregate supply and demand. This process pins down the hourly market price, which is equal to the marginal cost of the thermal unit operating on the margin. Similarly, the marginal emissions for that hour is determined from the intersection between the aggregate emissions curve and demand.

As more renewable power penetrates the market, it effectively displaces output of the previous marginal thermal unit. This output displacement gives rise to two external benefits:

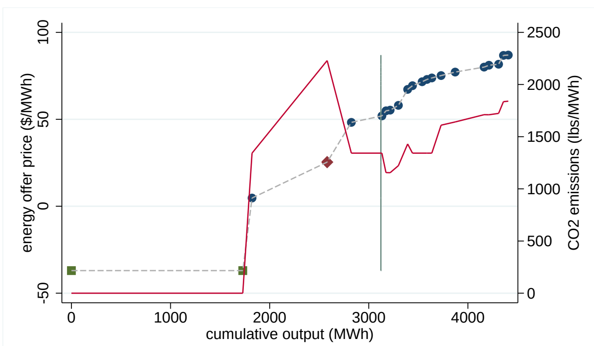
(i) production cost reduction benefit and (ii) emissions reduction benefit.

Transmission constraints play an important role in generating spatial variations in both types of the external benefits. During hours with no transmission constraint between locations, the four congestion zones of ERCOT clear as a single market. Additional output from the (infra-marginal) renewable generators, regardless of their location, will displace output of the same marginal thermal unit. This situation implies that the external benefits from renewable energy, both in the form of avoided production and emissions costs, are uniform across locations.

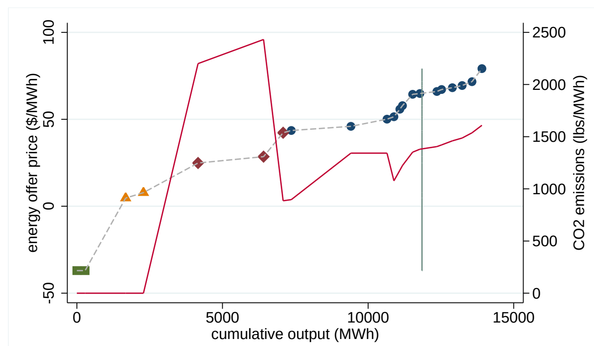
During hours with transmission constraints, the four zones will be cleared separately to serve zonal demand net of import or export. I refer to this as the "split market" equilibrium. When this event occurs, output from an (infra-marginal) renewable unit will replace output from the marginal thermal unit in the same region. In this case, the external benefits from renewable power are different across locations as shown in 3a–3d.

Figure 3: Split market equilibrium, December 10, 2008 at 8pm

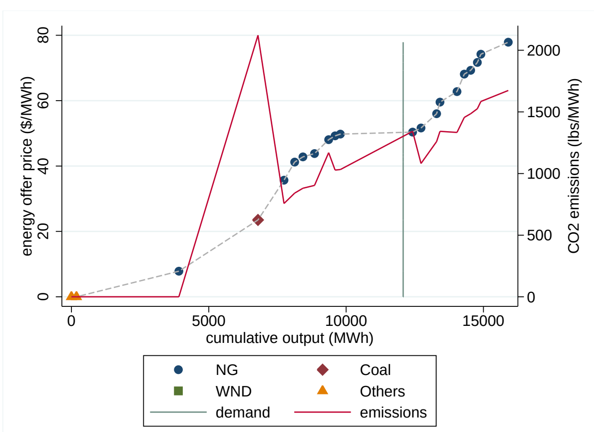
(a) West



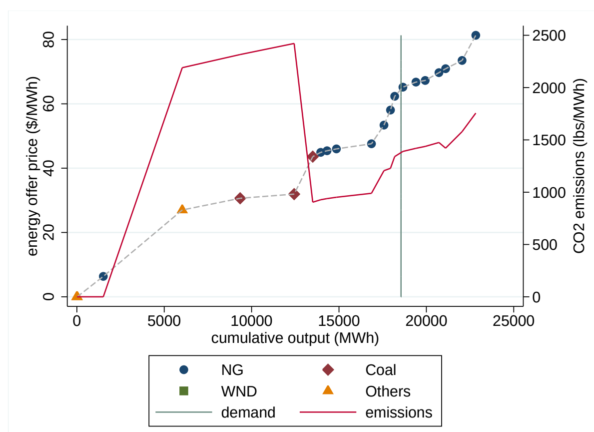
(b) South



(c) Houston



(d) North



3. Characterizing the Electricity Market Equilibrium

The electricity market model consists of two stages: the capacity investment stage and the electricity market stage. In the first stage, potential wind capacity investors choose locations and capacities to invest given the fixed investment cost and expected future energy prices. Once the investment decision is made, incumbents and entrants compete in the hourly electricity market that runs over a 20-year period.

There are three simplifying assumptions that I use for estimation and simulation. First, I assume that the ERCOT wholesale electricity market is competitive. This assumption is reasonable given a competitive market performance of the ERCOT wholesale market in 2008 (Potomac Economics, 2008). In addition, this assumption is particularly applicable for renewable units. Renewable generation units have almost zero marginal cost and account for such a small share of total generation in ERCOT.[6] Thus, they are almost always inframarginal in the hourly electricity market. This characteristic makes it difficult for renewable units to unilaterally manipulate the wholesale energy prices.

In general, however, the presence of interzonal transmission constraints in ERCOT creates incentives for firms to exercise local market power in the wholesale market. Market power could affect relative welfare ranking of different environmental policies depending on how each policy exacerbates or mitigates the incentives to exercise market power.[7]

Second, I assume that potential renewable entrants are homogeneous, forward-looking, and have perfect foresight. In reality, it is likely that potential renewable entrants will differ by their fixed cost of investment, productivity, experience, and ownership of other generation technology (coal, natural gas, or other renewable). Thus, assuming homogeneous and competitive entrants could produce investment equilibrium that is different from what would have occurred in reality. This difference will likely affect the magnitude of the welfare gains from different environmental policies, but not their relative welfare ranking.

Lastly, I assume that there is no new investments in non-renewable technology and that new investment in other renewable technologies are the same across policy scenarios. This assumption allows me to abstract away from modeling these other investments which can

[6] Wind generation accounts for around 6.2% of total generation in 2009 and up to around 10% in 2014. Source: `http://www.eia.gov/todayinenergy/detail.cfm?id=20051`.

[7] Market power is likely to be more severe under the emissions tax for two reasons. First, the simulation results suggests that the optimal emissions tax creates more congestion the the opportunity to exercise market power. This is because the policy raises the marginal costs of production in the import-constrained areas more than in others. The disproportionate cost increase creates a bigger need to transport energy across areas and increases the likelihood of congestion. Second, financial burden from the emissions tax encourages exits and increases the concentration of generation capacity, hence exacerbating market power compared to renewable energy subsidies (Fowlie et al., 2013).

significantly reduce computational complexity. A back-of-an-envelope calculation in section 7.3 supports this assumption by showing that the revenues earned by the potential non-renewable entrants in the long-run equilibrium are not high enough to justify any new investment.

In the following subsections, I describe different elements of the model as well as characterize equilibrium for each stage. To reflect the zonal feature of the ERCOT market prior to December 2010, I use subscript z to designate congestion zone: $z \in \{West, South, Houston, North\}$.

Consumer demand for energy

In general, short-run demand for wholesale energy is very inelastic to wholesale prices. This is because end-use customers do not face wholesale energy prices in real time. Instead, end-use customers face retail prices that are much less volatile than wholesale prices. Over a longer time horizon, end-use energy demand could become more price elastic since retail rates would have incorporated the changes in wholesale prices and consumers would respond to the state- and regional-level demand response initiatives (Joskow and Wolfram, 2012; Joskow, 2012). To allow for all of the above possibilities, I specify energy demand to have a generic form $Q^d_z(p_z)$ in this baseline model. I discuss specific demand parameterization for the simulation in section 5.

Generators

For each zone z, I label the *incumbent units* as $j = 1, \ldots, J_z - 1$ and the *potential entrant* as J_z. In this model, wind generation (denoted w) is the only entering technology in each zone. Let K^w_z be the total entering capacity in each zone and FC^w be a constant marginal (per MW) fixed cost of new wind capacity investment. Lastly, let c be the social cost of emissions, τ be the emissions tax (both are in \$ per unit of emissions), and s be the per MWh renewable production subsidy.

For the *entering wind generation technology*, the hourly marginal output when the aggregate wind investment is K^w_z is parameterized as

$$\gamma'_{z,h}(K^w_z) = a_{z,h} - b_{z,h} K^w_z. \tag{1}$$

This marginal wind energy output varies across time and location to reflect heterogeneity of the wind resource. It is further assumed to be decreasing in the aggregate wind investment to reflect the scarcity of land resource. Rational investor will choose to invest in the most productive locations first, follow by less productive locations. Hence, the marginal wind production is highest for the first wind farm and lowest for the last wind farm. This parameterization implies that the maximum available output given a total investment of K_z^w MW is $\gamma_{z,h}(K_z^w) = \int_0^{K_z^w}(a_{z,h} - b_{z,h}k)dk$.

For *non-wind technologies*, the maximum output of each unit is equal to its capacity $K_{z,j}$. Further, for each non-renewable unit j, denote mc_j as a constant variable cost of generation (variable fuel, operation and maintenance costs per MWh) and e_j as a constant emission rate (lbs or tons per MWh). I explain how to calculate the variable cost of generation in section 5.

Second-stage electricity market equilibrium

The electricity market equilibrium occurs hourly.[8] In what follows, I drop subscripts for month, day, and year to minimize notation.

Given the first stage entrants' capacity (K_z^w), a price-taking generator offers up to its maximum available output as long as the market price is higher than its marginal cost. Individual generator's supply decision is thus

$$q_{z,j}^s(p) = \begin{cases} K_{z,j} & \text{if non-renewable and} \quad mc_{z,j} \leq p \\ \gamma_{z,h}(K_z^w) & \text{if wind and} \quad mc_{z,w} \leq p \\ 0 & \text{otherwise.} \end{cases}$$

Summing across individual generators' supply curve, the hourly aggregate supply function for each zone is a step function

$$Q_z^s(p) = \sum_{j \in J_z} q_{z,j}^s(p).$$

Using the aggregate supply and demand for all the zones in each hour, the system operator chooses a vector of energy production $(x_{z,1}, \ldots, x_{J_z})$ to minimize the cost of procuring energy

[8] In fact, the 2008 balancing electricity market clears every 15 minutes. To reduce computational burden, I aggregate the demand and average out other relevant quantities to hourly intervals.

subject to the market-clearing and the inter-zonal flow constraints.

$$
\begin{aligned}
\text{Objective:} \quad & \underset{p^*=\{p_1^*,\ldots,p_z^*\},\mathbf{X}=\{x_{z,1},\ldots,x_{J_z}\}}{\text{minimize}} \sum_z \sum_{j\in J_z} mc_{z,j} x_{z,j} \\
\text{subject to} \quad & \\
\text{Market-clearing constraint:} \quad & \sum_z \sum_{j\in J_z} q^s_{z,j}(p^*) = \sum_z Q^d_z(p^*), \\
\text{Interzonal flow constraint:} \quad & implimit_z \le \sum_{j\in J_z} x_{z,j} - Q^d_z(p^*) \le explimit_z, \quad z \in \{W,S,H,N\}, \\
\text{Capacity constraint:} \quad & 0 \le x_{z,j} \le q^s_{z,j}(p)
\end{aligned}
$$

On average, the marginal cost of natural gas units are the highest, followed by oil, coal, nuclear, and renewable. Thus, renewable, nuclear, and coal units are among the first to be called to fulfill demand requirement. Natural gas and oil units have the highest marginal costs of production and are usually the marginal, price-setting units.

First-stage investment equilibrium

In the ERCOT region, only the West, South, and North congestion zones have good enough resources to accommodate investment in wind generation capacity. The wind capacity investment decision occurs for each zone $z \in \{W, S, N\}$ at the beginning of a 20-year period. In what follows, let the subscript y denotes year, d denotes day, and h denotes hour of day.

Given the *expected* zone-specific second-stage price (p^*_{ydhz}), quantity ($x_{j,ydh}$), constant marginal cost ($mc_{j,ydh}$), emission tax (τ), and renewable subsidy (s_j), a potential entrant in each zone chooses investment capacity to maximize his expected profit over a 20-year lifetime. The choice of a 20-year lifetime comes form a common assumption used in EIA's projection (U.S. Energy Information Administration, 2010). Since I assume that potential entrants have perfect foresight over future market condition, the expectation notation can be ignored. The maximization problem for potential wind entrants in each zone z is

$$
\max_{K^w_z} \quad NPV_w = \sum_y^{20} \frac{\sum_{d,h}(p^*_{ydhz} + s)x^w_{ydh}}{(1+r)^y} - FC^w \cdot K^w_z, \quad 0 \le x^w \le \gamma(K^w_z),
$$

with the corresponding first-order (zero-profit) condition

$$\forall z: \quad \sum_{y}^{20} \frac{\sum_{d,h}(p^*_{ydhz} + s)}{(1+r)^y} \frac{\partial x^w_{ydh}}{\partial K^w_z} = FC^w. \tag{2}$$

Note that the second-stage equilibrium price, p^*, is weakly decreasing in the first-stage capacity invested. Potential entrants are aware that his investment decision will affect the future market prices, but do not react strategically to it. This assumption is reasonable because wind generations are almost always infra-marginal. The first-order condition states that wind farm owners will invest in additional generation capacity until the expected marginal revenue is equal to the marginal fixed cost of investment.

Long-run equilibrium

A long-run equilibrium is characterized by the short-run electricity market clearing and the zero-profit conditions for all potential entrants. More formally:

Definition 1:
A long-run equilibrium is defined as a set of hourly zonal market prices, hourly energy production, and capacity of new generation, $\{p^*_z\}^4_{z=1}, \{x_{z,j}\}^{J_z}_{j=1}, \{K_{z,j}\}^{J_z}$, such that given demand, energy supply, emission tax/renewable subsidy, and a set of fixed cost, $\{Q^d_z(p)\}^4_{z=1}$, $\{Q^s_z(p)\}^4_{z=1}$, τ, s, $\{FC_{z,j}\}^{J_z}$, the following holds:

1. the conditions for the short-run electricity market equilibrium are satisfied, and
2. the last MW of new capacity invested just breaks even:

$$\begin{aligned} NPV_j \geq 0, \forall j \quad &\text{if} \quad K_j > 0, \\ NPV_j < 0, \forall j \quad &\text{if} \quad K_j = 0. \end{aligned}$$

4. Comparing Supply-side Environmental Policies

In this section, I analyze how different environmental policies affect social welfare through the following abatement channels: cross-plant fuel substitution (short-run), demand responses (short-run), and entry of renewable capacity (long-run). I consider four key policy scenarios: (i) unregulated scenario, (ii) *optimal* emissions tax scenario, (iii) status quo renewable subsidy scenario, and (iv) *optimal* variable subsidies. For conciseness, this section only summarizes the main results of welfare comparison. Full mathematical derivation is available in appendix Appendix A and Appendix B.

4.1. Social welfare

The metric for welfare performance is the net social benefit (W), which consists of the net consumer surplus (CS) plus the net producer surplus (PS), minus the environmental cost of CO_2 ($Ecost$) and the investment cost for new generation capacities ($InvCost$). Let c be the social cost of CO_2 and r be the discount rate. Further, let electricity demand, incumbent's aggregate marginal cost and aggregate emissions be approximated by smooth, differentiable functions $P(q)$, $mc(q)$, and $e(q)$, respectively. The discounted net social benefit over a 20-years time span can be expressed as

$$W(K) = CS + PS - Ecost - InvCost, \text{ or} \tag{3}$$

$$W(K) = \sum_{y,d,h} \int_0^{Q^*_{ydh}(K)} \frac{[P(q) - mc(q) - ce(q)]dq}{(1+r)^y} - FC^w \cdot K. \tag{4}$$

This expression has already taken into account revenues from emissions tax and expenditures for renewable energy subsidies. Both are assumed to be lump-sum transfers between consumers and producers. Theoretically, the social welfare should include another component, the *environmental quality*. However, this environmental quality variable is not well-defined and thus hard to measure. To proceed with the welfare comparison, I implicitly assume that the environmental quality component of the social welfare is the same across different environmental policies. Admittedly, this assumption creates a somewhat arbitrary baseline welfare and all the results should be interpreted with this caveat in mind.

4.2. Optimal environmental policies

Optimal emissions tax

The optimal emission tax that maximizes the long-run net social benefit has a rate equal to the social cost of carbon $\tau = c$.

In the framework used in this paper, the optimal emissions tax effectively engages in three emissions abatement channels. First, it encourages *cross-plant* fuel substitution. The substitution occurs because emissions tax raises the effective marginal cost for each thermal generator by the amount of their emissions externality. Thus, the marginal cost of emissions-intensive plants will increase by more than that of cleaner plants. Holding other market conditions constant, this shift in the marginal cost allow some output from cleaner thermal plants (e.g. gas-fired) to displace output from dirtier thermal plants (e.g. coal-fired) in the short run. Second, the optimal emissions tax encourages *electricity conservation* through an increase the market price for wholesale electricity. Last, the emissions tax creates a price signal that encourages *an efficient investment of cleaner technology* such as renewable and gas-fired generation. Tax-induced electricity price will be higher in areas with the higher marginal emissions. Thus, it will attract clean capacity investment to locations with highest environmental value.

Optimal variable subsidies

The optimal renewable production subsidies are set equal to the emissions cost of the marginal thermal generator at a particular time and location. Since the emissions cost of the marginal thermal generator can vary across time and locations, the optimal renewable subsidies will be differentiated and be referred to as the "optimal variable subsidies."

In a special case where the electricity demand is price elastic, renewable production subsidies can lead to lower wholesale electricity prices and higher electricity consumption than optimal. To account for the negative effect of demand response, the optimal variable subsidies need to be *scaled down* by a factor proportional to the price elasticity of demand.

The optimal variable subsidies engage in only one emissions abatement channel: inducing an efficient investment of renewable capacity. The differentiated subsidies will attract new renewable capacity investment to areas with the highest environmental benefits while having a minimal impact on cross-plant fuel substitution or investment of thermal capacity. This limited ability to engage in other emissions abatement channels make the optimal variable subsidies inferior to the optimal emissions tax.

Status quo uniform renewable subsidy

The status quo renewable subsidy policies that existed in ERCOT in 2008 are the federal Production Tax Credit of $23 per MWh and an Renewable Portfolio Standard (RPS).[9] For computational feasibility, I abstract away from explicitly modeling the RPS and define the status quo uniform subsidy as only capturing the production tax credit of $23 per MWh.

The decision to abstract away from modeling the RPS is arguably not far from realistic. Due to the aggressive federal production tax credit and good wind resource in Texas, ERCOT surpassed its 10,000 MW 2025 RPS target since 2009. This event sent the price of the Renewable Energy Credits (RECs) traded in the Texas market to under $2 per MWh since 2009. The RECs price has remained low and thus will have minimal impact on new renewable investestment.[10]

Since the status quo subsidy is a uniform subsidy, it is inferior to the optimal variable

[9] http://programs.dsireusa.org/system/program/detail/734 and Seehttp://programs.dsireusa.org/system/program/detail/182.

[10] See http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5.

subsidies because it is not set to reflect the true environmental benefit of renewable generation.

4.3. Comparing the long-run welfare performance

Let $K^*_{tax}, K^*_{vsub}, K^*_{quo}, K^*_{unreg}$ denote equilibrium renewable capacity investment under the optimal emissions tax, variable subsidy, status quo subsidy, and unregulated scheme, respectively. The formal welfare comparison between emissions tax and renewable energy subsidy involves recognizing that for the same level of renewable capacity investment, the optimal emissions tax $\tau = c$ induces additional short-run emissions abatement through cross-plant fuel substitution and demand conservation. Thus, for any level of renewable capacity investment, the social welfare profile under optimal emissions tax, $W_{tax}(K)$, is always above the social welfare profile under any of the renewable subsidy policies, $W_{sub}(K)$. The formal welfare comparison between different types of renewable subsidies involves recognizing that the optimal variable subsidies can coordinate a more efficient pattern of renewable investment and hence achieve a higher social welfare than the unregulated baseline and the status quo uniform subsidy.

With the equilibrium renewable capacity investment, long-run welfare ranking for different environmental policies is

$$W^{tax}(K^*_{tax}) \geq W^{sub}(K^*_{vsub}) \begin{cases} \geq W^{sub}(K^*_{quo}) \\ \geq W^{unreg}(K^*_{unreg}). \end{cases}$$

Figure 4 depicts this welfare ranking with the top curve representing the social welfare profile under the optimal emissions tax and the bottom curve representing the social welfare profile under renewable subsidy.

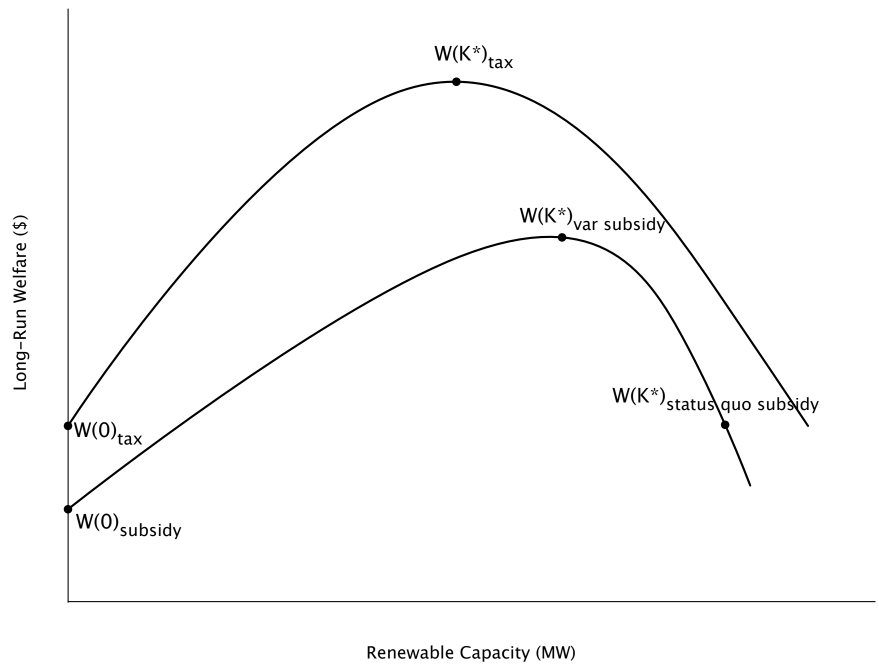
5. Policy Simulation, Data, and Model Calibration

Long-run equilibrium simulation

Using the model described in section 3, I simulate the long-run market equilibria under different policy conditions. Given the social cost of carbon, fixed cost of wind capacity investment, total demand, wind generation potential, and incumbents' electricity supply, I formulate the long-run equilibrium as a constrained linear programming problem (LP) and solve for the equilibrium prices, quantities, and wind capacity investment using the IBM ILOG CPLEX optimizer.[11] Since the equilibrium simulation is computationally intensive, I

[11] Available for free to researchers under IBM Academic Initiative.

Figure 4: Long-run welfare comparison. Note that the relative welfare performance between the status quo subsidy and the no regulation cases is ambiguous. This figure portrays one possibility in which the status quo subsidy outperforms the no regulation case.



perform each simulation using hourly data from 48 representative days in 2008 and assume the market conditions for the next 20 years stay at its 2008 level.[12] Specifically, I assume that the incumbents' energy offer schedules, thermal capacity mix, demand level, and transmission constraints are constant at their 2008 levels. I solve for the short-run electricity market equilibrium for the representative days and calculate an annualized profit for this year. With the above stationary assumption, the profit stream is the same for the next 19 years and is used to determine the equilibrium wind capacity investment.

Hourly operational data

The ERCOT data archive provides information on the real-time energy supply, energy flows, market-clearing prices, and demands in 2008. Table 1 provides summary statistics for these variables for the 48 representative days in 2008.

Incorporating demand elasticity

The most straightforward demand specification is a constant-elasticity one (for example, $logQ = a - b \cdot logP$). However, this demand specification is undefined when prices become negative. Since allowing energy producers (especially wind generators) to earn negative

[12] These 48 representative days are the second and forth Wednesdays and Sunday of each month.

Table 1: Summary Statistics for the hourly operation data of 48 representative days in 2008

	Mean	Standard Dev.	Min	Max
Energy price ($/MWh)	59.33	76.99	-25.70	1,992.09
Total balancing energy (MWh)	-412.04	1,905.09	-5,799.00	6,971.00
Total ERCOT demand (MWh)	35,208.38	8,444.29	22,250.10	57,948.86
Fraction of hours with congestion	0.07	0.14	0.00	0.75
Number of observations (hours)	1,152			

prices is a very important feature of my model, I choose a linear demand specification of the form $Q = a - b \cdot P$. One potential issue with linear demand is that quantity demanded can become negative at very high prices. Such behavior is not observed in this case.

To calculate the slope and intercept of demand for each elasticity parameter, I follow Fell and Linn (2013). Specifically, I first calculate the zone-specific slope b_z that results in the *average* demand elasticity of -0.2 as my central case. This value is intended to capture the long-run elasticity of demand. As mentioned in Fell and Linn (2013), existing studies estimate the long-run price elasticity of demand ranging from -0.2 to near -1 (Fell and Paul, 2012; Alberini et al., 2011; Paul et al., 2009; Reiss and White, 2005). I choose a conservative estimate of -0.2 to be my central case. I assume that the zone-specific slopes are constant across hours, days, and months. Given the slope of demand (b_z), I back out zone- and hour-specific intercepts (a_{zh}) using the observed market price and quantity. For the sensitivity analysis, I also specify demand with average elasticity of 0, -0.05 and -0.4.

Incumbent units

A complete list of existing generation units in ERCOT and their characteristics are obtained from ERCOT website and the Environmental Protection Agency's eGRID database.[13] Heat rate, variable operating and maintenance cost (O&M), and emissions rates will be used to calculate the marginal cost of each type of incumbents and wind entrants. The EIA's form 923 provides data on fuel cost needed to compute marginal cost for each unit.[14] Table 2 summarizes the characteristics of each incumbent technology.

Wind capacity

I use data on wind power output from year 2007 to 2012 to estimate the hourly marginal output function of new wind farms in three ERCOT congestion zones (West, South, and North).

[13] http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html
[14] http://www.eia.gov/electricity/data/eia923/

Table 2: Characteristics of the incumbent technologies

Technology	Capacity (MW)	Heat Rate ($\frac{\text{mmbtu}}{\text{MWh}}$)	Variable o&m ($/MWh)	Fixed o&m ($/kW-y)	Emissions Rate (lbs/MWh)		
					SO2	NOx	CO2
Coal	16,640	9.68	5	25.5	6.33	1.39	2,287.38
Natural Gas	46,939	9.05	4.3	14.68	0.02	1.05	1,341.84
Nuclear	5,138	10	4	73	0	0	0
Others	214.6	8.8	6.82	14.4	0	0	0
Hydro	460	0	0	18	0	0	0
Wind	5,242	0	0	29.25	0	0	0

Note: The data is obtained from the EPA's eGRID database and the EIA's form 923 for year 2009 and 2009.

The hourly marginal output function is constructed as follows. For each hour and zone, I rank existing wind farms from the most productive to the least productive according to the hourly capacity factor (γ'). Assuming that investors choose the most productive site first and move down the ranking, I calculate the cumulative wind capacity associated with each existing site (K_z^w). I then estimate coefficients $a_{z,h}, b_{z,h}$ of equation 1 using ordinary least square.[15]

The estimated coefficients are used to calculate the maximum potential power output of the marginal wind entrant in region z when the cumulative wind capacity is at K_z^w,i.e.

$$\gamma_{z,h}(K_z^w) = \int_0^{K_z^w} (\hat{a}_{z,h} - \hat{b}_{z,h}k)dk.$$

Each potential wind entrant will submit an energy offer that consists of this maximum potential output and its marginal cost (zero or negative).

Fixed cost of wind capacity investment

I use the fixed cost of $1.96 million per MW for onshore wind farm installation. The number is provided by U.S. Energy Information Administration (2010), which is also consistent with the capacity-weighted average of $1.94 million per MW for wind farm projects installed in 2012 (U.S. Department of Energy, 2013a).

Constructing the aggregate marginal cost curve

Assuming that generators are competitive and price-taking, the aggregate marginal cost curve is constructed as follows. First, I calculate each incumbent plant's marginal cost of

[15] Estimation coefficients are reported in Appendix E.

production

$$\begin{aligned} \text{thermal } (c/g)\text{:} \quad & mc_j = hr_j f_{c/g} + e_j \tau + o\&m_j, \\ \text{renewable:} \quad & mc_r = -s + o\&m_j, \end{aligned}$$

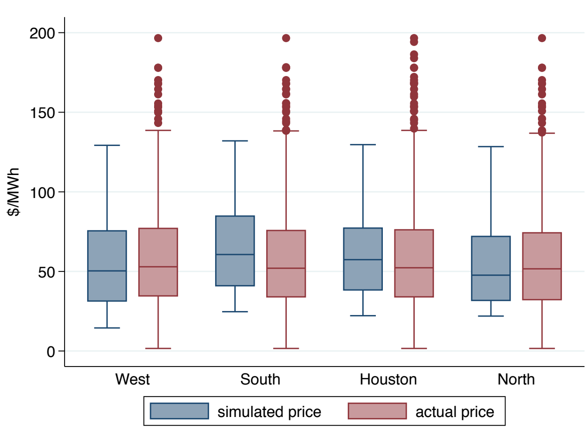
where hr_j is heat rate (mmbtu per MWh), $f_{c/g}$ is fuel cost ($ per mmbtu), s is the renewable production subsidy, and $o\&m_j$ is variable plus amortized fixed operation and maintenance cost ($ per MWh). For simplicity, I construct one representative marginal cost curve for each month and use it for every hour and day in that month. Then I scale down each plant's maximum operating capacity by its capacity factor as reported in the eGRID database and determine each plant's operation status in each month. Taking only the operating plants, I rank them by their marginal costs and calculate the cumulative capacity at each price. The pairs of marginal costs and cumulative capacities constitute the aggregate marginal cost curve for that month.

6. Simulation Results

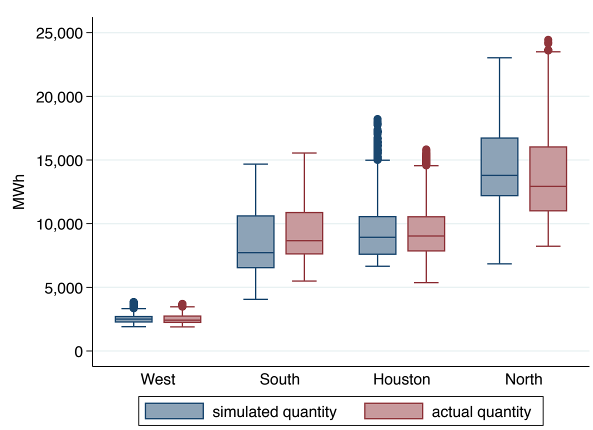
6.1. Model validation

Figure 5 shows the box plots that compare the average simulated electricity prices and outputs to the actual data. I generate these simulated prices and quantities by restricting new wind capacity investment to be zero and solving for the market equilibrium with no environmental regulation. On average, these simulated prices and quantities track the actual real-time prices and quantities quite well.

Figure 5: Model Validation Results



(a) Simulated vs. Actual Prices



(b) Simulated vs. Actual Quantities

In the following subsection, I report the simulated long-run equilibria and the corresponding change in social welfare under five different policy scenarios: (i) baseline unregulated scenario, (ii) status quo renewable subsidy, (iii) optimal emissions tax, and (iv) optimal variable subsidies. I assume the average demand elasticity of -0.2 for the central case. I report additional results for different demand elasticities in section 7.

6.2. Simulated market equilibrium: central case

Table 3 reports equilibrium quantities for three different social costs of carbon (SCC): \$5, \$35, and \$55 per ton.[16] Equilibrium quantities associated with the unregulated baseline and the status quo are the same throughout because these policies do not change with the SCC.

Equilibrium prices and subsidies

For each policy scenario, the optimal emissions tax and subsidies increase with the SCC. The increase in the tax rate directly raises electricity prices at higher SCC.[17] The increase in optimal subsidies, in contrast, encourages new renewable investment that leads to lower equilibrium prices at higher SCC.

Total electricity demand

Hourly demand is aggregated across the four congestion zones. By comparing equilibrium demand under each policy to the demand under the unregulated baseline, it is clear that emissions tax encourages electricity conservation while all renewable subsidies encourage more electricity consumption. The intuition is simple: the emissions tax raises electricity prices and suppresses demand while renewable subsidies suppress prices and increase demand.

Wind capacity investment and production

For each policy scenario, total wind capacity investment and electricity production increase with the SCC. Additionally, total investment under the optimal variable subsidies tracks closely with that under the optimal emissions tax. This is because both the optimal

[16] Interagency Working Group on Social Cost of Carbon (2013) defines the SCC as monetary damages resulting from a marginal increase in carbon emissions in a given year. The estimate includes a wide range of social costs such as changes in net agricultural productivity, damages to human health, damages from sea level rises, and the value of ecosystem services. Three values of the SCC are estimated for each year at the discount rates of 2.5, 3, and 5 percent. At 5% discount rate, the average SCC range from \$11/ton in 2010 to \$27/ton in 2050. At lower discount rates, the average SCC range from \$33/ton to \$71/ton (at 3%) and \$52/ton to \$98/ton (at 2.5%). Of all the values, the Working Group recommended \$38 per ton of CO_2 for policy analysis.

[17] There is also a countervailing price-reduction effect from renewable entry. However, this price-reduction effect is dominated by the effect of emissions tax on prices.

emissions tax and variable subsidies are designed to encourage efficient investment in new capacity.

Total investment in wind capacity induced by the status quo subsidy is most similar to total investment under the optimal variable subsidies and the emissions tax at the SCC of \$55 per ton. As will be discussed in the next subsection, this is the SCC level to which the benefit from subsidy differentiation can be inferred.

Frequency of transmission congestion

In the long-run equilibrium with additional wind capacity investment, interzonal transmission lines become congested in more than 80 percent of all the hours. As will be apparent shortly, the frequent congestion contribute to a substantial variation in the market prices and marginal environmental benefit of wind generation across zones.

Zonal prices, subsidies, and investment

Table 4 reports zone-specific electricity prices, subsidies, and wind capacity investment under the optimal emissions tax, status quo subsidy, and optimal variable subsidies. There are two important observations from the table. First, there is a non-trivial variation in the marginal environmental benefits of wind generation across zones as reflected in the values of the optimal variable subsidies. In particular, table 4 suggests that the environmental value of wind power is highest in the North zone and lowest in the West zone. Second, because of this variation, the optimal variable subsidies induce higher investment in the North zone and lower investment in the West zone compared to the status quo uniform subsidies. This can be best seen at the SCC of \$55 per ton where total investment under the two policies are comparable. More specifically, the optimal variable subsidies result in 125 percent higher investment in the North zone, 21 percent higher investment in the South zone, and 8 percent lower investment in the West zone.

This asymmetric investment response at the SCC of \$55 per ton is due to the fact that wind resource in the West zone is much more productive than the North and South zones. Figure 6 plots the average hourly capacity factor of each region under the optimal variable subsidies and SCC of \$55 per ton. The most productive sites are in the west congestion zones, followed by the north and the south, respectively. Therefore, under the optimal variable subsidies, much more new investment in the North and South zones is needed to compensate for the reduction in investment and output from the West zone.

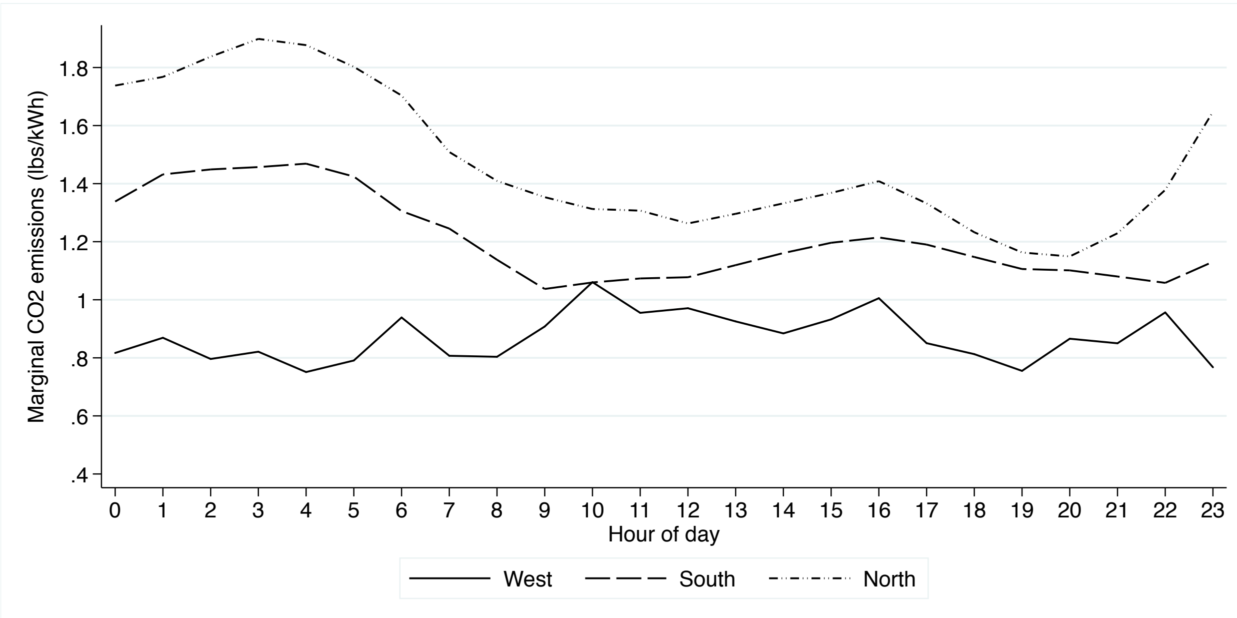
Table 3: Equilibrium quantities, central case with average demand elasticity of -0.2

Variable	Unregulated	Emission Tax	Status Quo	Variable Subsidies
Social cost of carbon (scc): $5/ton				
Prices ($/MWh)	55.90	58.68	54.19	55.80
Subsidy ($/MWh)	0.00	0.00	23.00	4.02
Demand (MWh)	34,896.34	34,621.02	35,116.31	34,907.27
Wind Output (MWh)	4.63	97.32	827.28	60.75
Wind Investment (MW)	13.27	204.50	1,864.05	149.45
Frequency of Congestion (%)	0.84	0.83	0.90	0.84
Social cost of carbon (scc): $35/ton				
Prices ($/MWh)	55.90	74.93	54.19	54.75
Subsidy ($/MWh)	0.00	0.00	23.00	21.25
Demand (MWh)	34,896.34	32,835.18	35,116.31	35,041.21
Wind Output (MWh)	4.63	697.34	827.28	583.19
Wind Investment (MW)	13.27	1,544.92	1,864.05	1,302.29
Frequency of Congestion (%)	0.84	0.89	0.90	0.87
Social cost of carbon (scc): $55/ton				
Prices ($/MWh)	55.90	85.53	54.19	54.24
Subsidy ($/MWh)	0.00	0.00	23.00	32.99
Demand (MWh)	34,896.34	31,567.12	35,116.31	35,107.68
Wind Output (MWh)	4.63	881.82	827.28	820.83
Wind Investment (MW)	13.27	2,032.82	1,864.05	1,896.32
Frequency of Congestion (%)	0.84	0.93	0.90	0.89

Note: The table reports *demand-weighted average* hourly prices and subsidy across the four congestion zones. Demand, wind output, and wind investment are *aggregated* across the four zones.

Figure 6: Marginal emissions and wind generation potential, evaluated at equilibrium investment under the optimal variable subsidies and SCC of \$55/ton

(a) Equilibrium marginal emissions



(b) Equilibrium Wind power generation potential

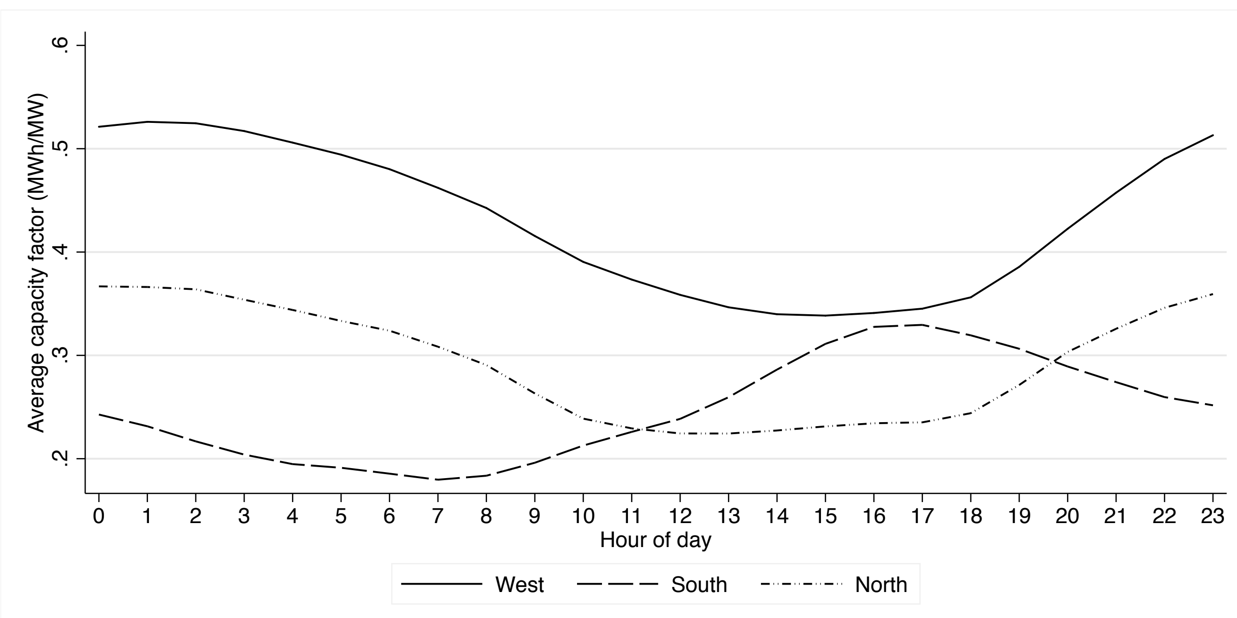


Table 4: Equilibrium quantities by zone, central case with average demand elasticity of -0.2

Variable	Emission Tax			Status Quo			Variable Subsidies		
	W	S	N	W	S	N	W	S	N
Social cost of carbon (scc): $5/ton									
Prices ($/MWh)	51.5	70.1	56.2	40.3	67.0	52.1	48.7	67.5	53.1
Subsidy ($/MWh)	0.0	0.0	0.0	23.0	23.0	23.0	2.5	5.4	4.2
Wind Investment (MW)	151.5	53.0	0.0	1,480.4	309.9	73.8	55.1	94.3	0.0
Social cost of carbon (scc): $35/ton									
Prices ($/MWh)	60.7	85.1	75.6	40.3	67.0	52.1	44.2	67.1	52.3
Subsidy ($/MWh)	0.0	0.0	0.0	23.0	23.0	23.0	13.9	20.2	23.3
Wind Investment (MW)	1,204.0	254.3	86.6	1,480.4	309.9	73.8	934.6	279.4	88.3
Social cost of carbon (scc): $55/ton									
Prices ($/MWh)	64.7	96.0	88.3	40.3	67.0	52.1	41.2	66.9	52.0
Subsidy ($/MWh)	0.0	0.0	0.0	23.0	23.0	23.0	21.7	30.2	36.7
Wind Investment (MW)	1,510.1	362.5	160.2	1,480.4	309.9	73.8	1,356.0	374.6	165.7

Note: The table shows average energy price, subsidy, and wind capacity investment for the three congestion zones with non-zero wind capacity investment—West (W), South (S), and North (N)

6.3. Welfare comparison: central case

Figure 7 displays the annualized welfare change over a range of SCC. Table 5 presents more details on the change in welfare under each policy scenario at the SCC of $5, $35, and $55 per ton. The figures represent the absolute annualized welfare gain from the unregulated baseline for the respective policy (i.e. emission tax, status quo renewable subsidy, and optimal variable subsidies). The column "Var Sub Margin" reports welfare improvement from switching from the status quo subsidy to the optimal variable subsidies, expressed as a percentage of the welfare gain under the status quo.

Three interesting observations are worth highlighting. First, the status quo subsidy outperforms the unregulated baseline only when the SCC is higher than $27 per ton. Second, for this range of SCC, the optimal variable subsidies outperform the status quo subsidy by small to moderate margins. More specifically, the optimal variable subsidies outperform the status quo by at most 27.1 percent at the SCC of $35 per ton, and at least 2.9 percent at the SCC of $55 per ton.[18] The welfare gap between the status quo and the optimal variable subsidies is smallest at the SCC of $55 per ton because the status quo subsidy leads to investment level that is close to being optimal at this level of SCC.

These observations suggest that switching from the status quo to optimal variable sub-

[18]The tabular form for this figure can be found in appendix Appendix C.

sidies offers a moderate welfare gain for a reasonable range of the SCC (between $27 and $50 per ton). Further, most of the welfare advantage of the optimal variable subsidies comes from inducing the right *level* of investment and not so much from coordinating more efficient investment through subsidy differentiation. In particular, the welfare gain from subsidy differentiation is at most 2.9 percent of the gain achieved under the status quo subsidy.

Table 4 and figure 6 provide important clues on the limited welfare advantage of the optimal variable subsidies: there is a negative correlation between wind resource productivity and the marginal emissions (or environmental values). In other words, while the North zone has higher marginal emissions, it also has less productive wind resource than the West zone. Thus, when the optimal variable subsidies shift more investment into the North zone and less investment into the West zone, they do so in the way that investment has to increase much more in the North zone because wind resources are less productive. This mechanism leads to a large increase in wind capacity investment cost that offsets the gain from emissions reduction.

Last, and not surprisingly, the emissions tax unambiguously leads to the largest welfare gain from the unregulated baseline. Its welfare gain become significantly larger at higher SCC. By inspecting each component of the welfare change, we can see that the optimal emissions tax leads to a large decline in consumer surplus. The loss of consumer surplus, however, is more than offset by the large benefits from the production and emissions cost saving. All of the three emissions abatement channels are responsible for this large welfare advantage of the emissions tax. I explore the relative importance of each channel in subsection 7.1.

Figure 7: Long-run social welfare across policies, central case with average elasticity -0.2

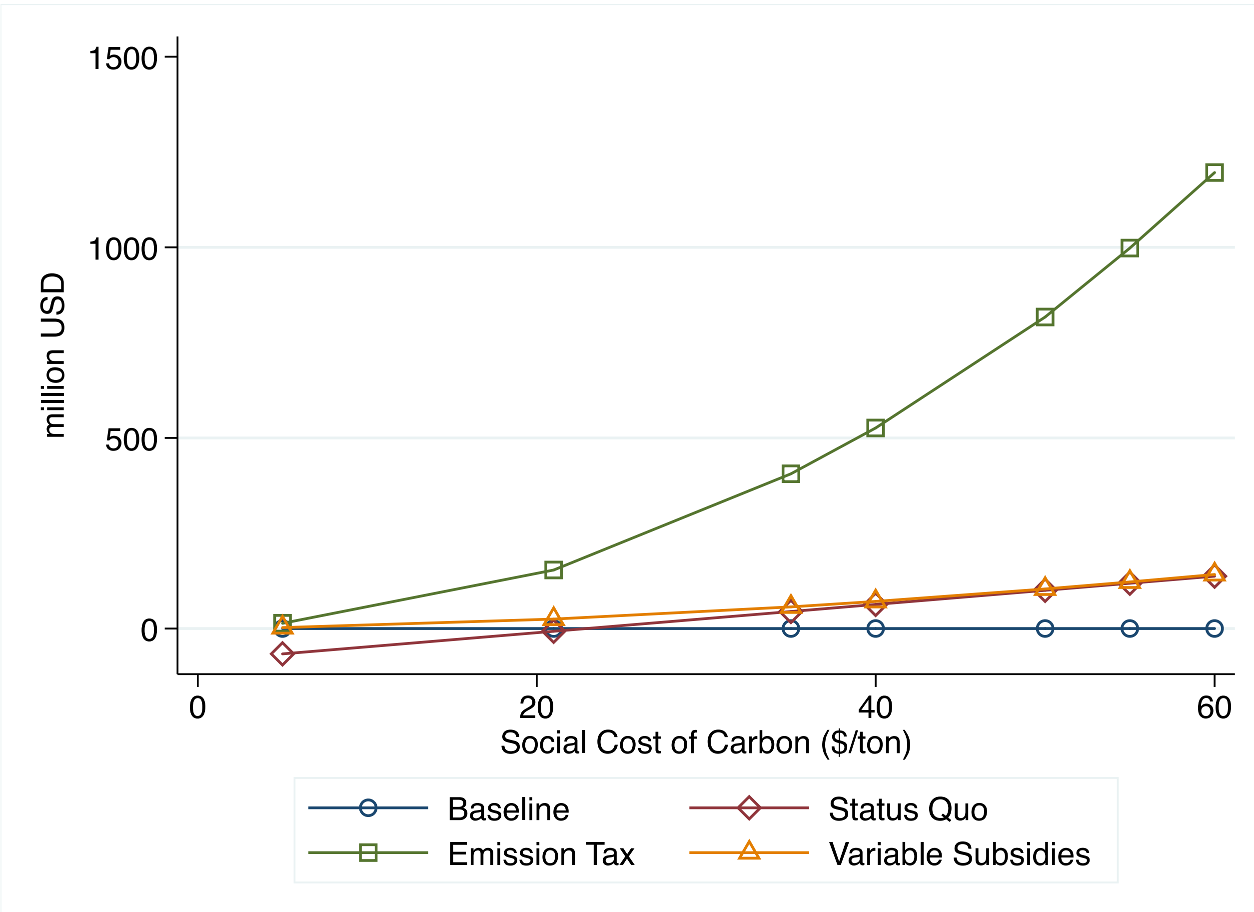


Table 5: Welfare decomposition, central case with average demand elasticity of -0.2

Variable	Unreg. Baseline	Emission Tax	Status Quo	Variable Subsidies	Var Sub Margin
Social cost of carbon (scc): \$5/ton					
Δ Welfare (\$ M)	0.0	13.7	-66.5	2.5	103.8
Δ Producer Surplus (\$ M)	0.0	852.0	-122.6	0.6	
Δ Consumer Surplus (\$ M)	0.0	-808.8	442.4	30.4	
Δ Emission Cost (\$ M)	0.0	-12.3	-18.5	-1.3	
Δ Wind Investment Cost(\$ M)	0.0	41.8	404.7	29.8	
Social cost of carbon (scc): \$35/ton					
Δ Welfare (\$ M)	0.0	405.9	44.7	56.8	27.1
Δ Producer Surplus (\$ M)	0.0	5,377.6	-122.6	-62.0	
Δ Consumer Surplus (\$ M)	0.0	-5,454.1	442.4	307.9	
Δ Emission Cost (\$ M)	0.0	-817.3	-129.7	-92.8	
Δ Wind Investment Cost(\$ M)	0.0	334.9	404.7	281.9	
Social cost of carbon (scc): \$55/ton					
Δ Welfare (\$ M)	0.0	998.1	118.8	122.3	2.9
Δ Producer Surplus (\$ M)	0.0	7,754.7	-122.6	-108.1	
Δ Consumer Surplus (\$ M)	0.0	-8,482.2	442.4	438.1	
Δ Emission Cost (\$ M)	0.0	-2,167.2	-203.8	-204.0	
Δ Wind Investment Cost(\$ M)	0.0	441.6	404.7	411.8	

Note: All the figures represent changes in welfare and its components from the unregulated baseline. Δ Welfare = Δ PS + Δ CS - Δ Emissions Cost - Δ Wind Investment Cost. *Var Sub Margin* denotes the welfare advantage of the optimal variable subsidies over the status quo subsidy, expressed as a percentage of the welfare gain under the status quo subsidy.

7. Sensitivity Analyses and Extensions

7.1. Sensitivity analysis: demand elasticity

To further assess the relative importance of each emissions abatement channel, I simulated additional long-run equilibria across various levels of demand elasticity. The results are summarized in table 6.

Table 6: Relative welfare gain under alternative demand elasticity, social cost of carbon $55/ton

Demand Elasticity	2008 Natural Gas Price			
	Emission Tax	Status Quo	Variable Subsidies	Var Sub Margin
-0.40	1,453.8	83.4	86.7	4.0
-0.20	998.1	118.8	122.3	2.9
-0.05	580.6	162.0	166.7	2.9
Inelastic	447.1	174.7	196.2	12.3

Note: The figures represent absolute annualized welfare gain under each policy from the unregulated baseline. *Var Sub Margin* denotes the welfare advantage of the optimal variable subsidies over the status quo subsidy, expressed as a percentage of the welfare gain under the status quo subsidy.

Effect of demand response

From table 6, relative welfare gain under the optimal emissions tax increase with demand elasticity. More specifically, the optimal emissions tax outperforms the variable subsidies by $1,367.1 million per year under high demand elasticity (-0.4) and by only $250.9 million per year under inelastic demand. In other words, turning off demand response reduces the relative advantage of the optimal emissions tax by as large as $1,116.2 million per year.

Note also that both types of renewable subsidies perform worse at higher demand elasticities. This is due to the unintended downward pressure of the renewable electricity subsidies on electricity prices. Lower electricity prices lead to too much electricity consumption from the efficiency standpoint and result in a welfare loss. This loss does not occur if demand is perfectly inelastic.

Effect of cross-plant substitution

In the case of perfectly inelastic demand, the welfare advantage of the optimal emissions tax over the optimal variable subsidies is driven mainly by its ability to induce cross-plant fuel substitution. The last row of table 6 suggests that even without demand response, emissions abatement through cross-plant fuel substitution still allows the optimal emissions tax to outperform the variable subsidies by $250.9 million per year.

Effect of renewable capacity investment

There are two aspects of renewable capacity investment that affect emissions abatement: the *level* of investment and the *location* of investment. The optimal variable subsidies lead to the optimal level and location of new investment that maximizes social welfare at all SCC. The status quo subsidy, however, only induces a certain level of new investment that may be close to optimal for a certain level of the SCC.

For the SCC of $55 per ton reported in table 6, the status quo subsidy leads to too much investment when demand elasticity is high (-0.4) and too little investment when demand elasticity is low (-0.05 and inelastic). Nonetheless, the status quo subsidy delivers welfare gain of at least $83.4 million per year over the unregulated baseline. Switching from the status quo to the optimal variable subsidies result in incremental welfare gain that range from 2.9 to 12.3 percent of the gain achieved under the status quo. These gains reflect the benefits of optimizing both the level and location of new investment.

As shown in table 3, at the SCC of $55 per ton and demand elasticity -0.2, total investment induced by the status quo subsidy is almost equal to the investment induced by the optimal variable subsidies. The fact that welfare improvement from the optimal variable subsidies is only 2.9 percent of the gain from the status quo suggests that the benefit from coordinating efficient renewable investment across locations are minimal. Most of the welfare advantage of the optimal variable subsidies over the status quo subsidy comes through inducing the right level of investment.

Combining all the results, we can see that demand conservation is a major contributor to the efficiency gain, followed by cross-plant fuel substitution and the right level of renewable capacity investment. Beyond these measures, redistributing renewable investment across location results in only a moderate to minimal welfare improvement. The results lead to an important policy implication: policies that stimulate demand conservation and cross-plant fuel substitution are much more effective than those that encourage efficient renewable capacity investment.

7.2. Sensitivity analysis: low natural gas price (2012)

Since 2008, the price of natural gas has been consistently declining thanks to the breakthrough in hydraulic fracking technology. Low natural gas price increases competitive advantage of natural gas plants by lowering their marginal cost of production. This triggers cross-plant substitution between coal and gas generators under all policy scenarios. The more frequent coal-gas substitution has two important implications. First, coal will become the marginal fuel more often in all locations. This means that the marginal emissions will be higher and less heterogeneous since additional renewable output will displace output and emissions from coal plants. The reduced variability in the marginal emissions will decrease the welfare gain from subsidy differentiation. Second, the ability of the emissions tax to induce cross-plant substitution will be enhanced compared to the case with high natural gas price.

Natural gas price and the gain from subsidy differentiation

Table 7 reports welfare performance of each policy under the high (2008) and low (2012) natural gas prices, assuming demand elasticity of -0.2 and the fixed cost of investment of \$1.96 million per MW. Since electricity prices under the 2012 scenario are significantly lower than prices under the 2008 scenario, new investment in renewable capacity under the 2012 scenario will be much lower than investment under the 2008 scenario. For the purpose of this discussion, I report welfare performance for the SCC of \$35 per ton and above since these are the SCC values that result in some investments in new wind capacity.[19]

Table 7: Relative welfare gain under alternative social cost of carbon, 2008 and 2012 natural gas price, demand elasticity of -0.2

Social Cost of Carbon ($/ton)	2008 Natural Gas Price				2012 Natural Gas Price			
	Emission Tax	Status Quo	Variable Subsidies	Var Sub Margin	Emission Tax	Status Quo	Variable Subsidies	Var Sub Margin
35	405.9	44.7	56.8	27.1	586.4	10.4*	10.4*	0.4*
40	526.1	63.2	71.1	12.5	748.2	19.3	21.4	11.1
50	817.2	100.3	103.9	3.6	1,110.7	37.1	51.4	38.4
55	998.1	118.8*	122.3*	2.9*	1,310.0	46.1	69.5	50.9
60	1,196.1	137.3	141.8	3.2	1,518.5	55.0	89.5	62.8

Note: The figures represent absolute annualized welfare gain under each policy from the unregulated baseline. *Var Sub Margin* denotes the welfare advantage of the optimal variable subsidies over the status quo subsidy, expressed as a percentage of the welfare gain under the status quo subsidy.

To assess the role of subsidy differentiation under the two natural gas price scenarios, I compare the welfare performance at the SCC of \$55 per ton under the 2008 price and at the SCC of \$40 per ton under the 2012 price. These situations, marked with asterisks *, are those where the status quo subsidy induces total investment that is most similar to the optimal variable subsidies. Thus, the welfare gap between the two subsidies would mostly come from subsidy differentiation. Under the 2012 natural gas price and the SCC of \$40 per ton, subsidy differentiation offer an incremental welfare benefit of 0.4 percent on top of the welfare gain achieved under the status quo subsidy. This is to be contrasted with the 2.9

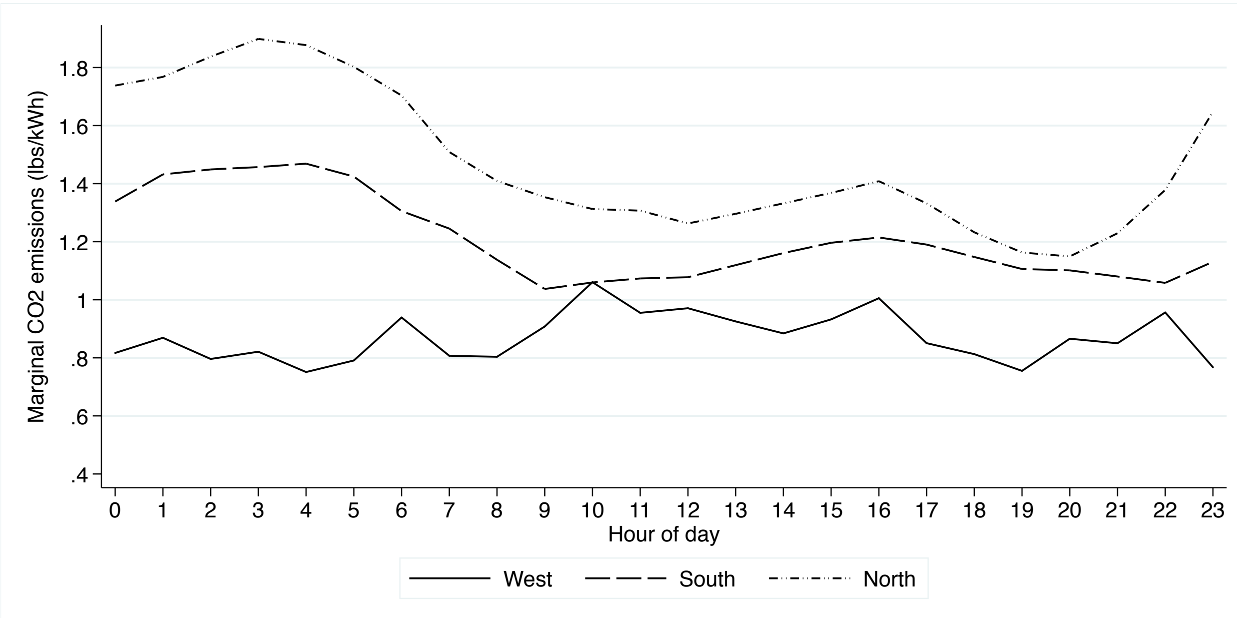
[19] The results for all SCC are available in appendix Appendix D.

percent gain on top of the gain achieved under the status quo subsidy at the SCC of $55 per ton under the 2008 natural gas price.

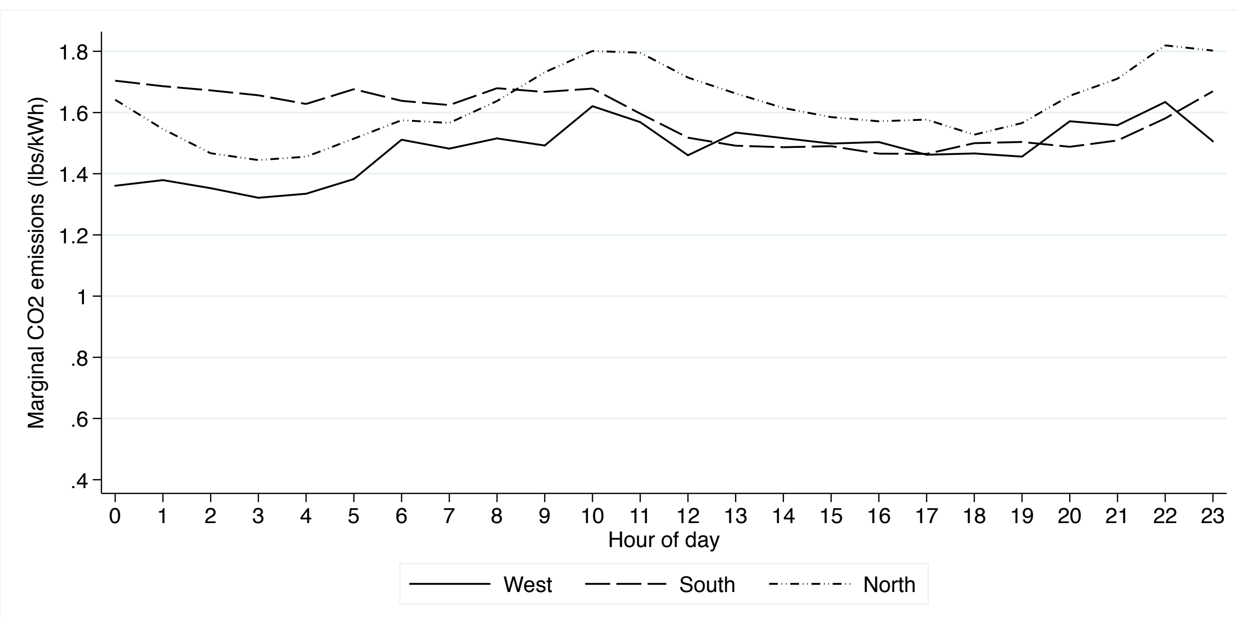
Low natural gas prices result in lower benefits from subsidy differentiation due two factors. First, there is much less variation in the marginal emissions under the 2012 natural gas price than under the 2008 natural gas price because coal units become marginal more often in all the zones. Figure 8 depicts this phenominon. Second, low electricity prices in 2012 result in less overall investment, making the effect of subsidy differentiation harder to detect.

Figure 8: Marginal emissions, evaluated at equilibrium investment under the optimal variable subsidies, base year 2008 and 2012

(a) 2008 Natural Gas Price, SCC of $55 per ton



(b) 2012 Natural Gas Price, SCC of $35 per ton



Natural gas price and the gain from cross-plant fuel substitution

Table 8 reports welfare performance of each policy under various demand elasticities for both 2008 and 2012 natural gas prices and the SCC of $55 per ton. As before, the welfare gain from cross-plant substitution induced by the emissions tax can be inferred from comparing the welfare performance between the emissions tax and the optimal variable subsidies when demand is perfectly inelastic.

Table 8 suggests that welfare gain from cross-plant substitution under low natural gas price (2012) is $570.7 million per year while the gain under high natural gas price (2008) is only $250.9 million per year. Thus, lower natural gas price enhances the ability of the emissions tax to induce cross-plant substitution by more than twice as much.

Table 8: Relative welfare gain under alternative demand elasticity, social cost of carbon $55/ton

Demand Elasticity	2008 Natural Gas Price				2012 Natural Gas Price			
	Emission Tax	Status Quo	Variable Subsidies	Var Sub Margin	Emission Tax	Status Quo	Variable Subsidies	Var Sub Margin
-0.40	1,453.8	83.4	86.7	4.0	1,858.9	39.3	56.8	44.5
-0.20	998.1	118.8	122.3	2.9	1,310.0	46.1	69.5	50.9
-0.05	580.6	162.0	166.7	2.9	826.2	50.9	79.7	56.6
Inelastic	447.1	174.7	196.2	12.3	636.5	31.4	65.8	109.5

Note: The figures represent absolute annualized welfare gain under each policy from the unregulated baseline. *Var Sub Margin* denotes the welfare advantage of the optimal variable subsidies over the status quo subsidy, expressed as a percentage of the welfare gain under the status quo subsidy.

In sum, low natural gas price reduces the welfare gain from subsidy differentiation because of the more homogeneous environmental benefits and the low price level that allows less investment in equilibrium. Additionally, low natural gas prices leads to a much larger welfare gain from cross-plant substitution induced by the emissions tax.

7.3. Considering investment in coal and gas capacity

One simplifying assumption used in the simulation model is that there is no additional investment in coal or gas-fired generation capacity in equilibrium. In this subsection, I justify this assumption by showing that the equilibrium prices under the central case are not high enough to sustain any new investment in coal and gas generation capacity.

To begin the analysis, I assume three types of hypothetical thermal entrants: coal unit, natural gas (combined cycle) unit, and natural gas (combustion turbine) unit, each has 1 MW capacity. Further, I assume that these hypothetical entrants are infra-marginal and that their capacity factor is 100 percent. These optimistic assumptions make the gross revenue calculated here the upper bound of the actual revenue.

To calculate the *gross revenue*, I use the equilibrium electricity prices under the variable subsidies policy, the SCC of $35 per ton, the average demand elasticity of -0.2, and the 2008 natural gas price.

The variable cost for each potential entrants is calculated from the heat rate and variable o&m estimates provided in ERCOT's 2012 State of the Market Report. I supplement this information with data on coal and natural gas price in 2012 from the EIA's form 923.

The final annualized *net revenue* per kW-year is calculated by subtracting the annualized variable cost (in $ per kW-year) from the annualized gross revenue (in $ per kW-year). Since the gross revenue is calculated based on the 2008 natural gas prices, while the variable cost is calculated based on the 2012 natural gas prices, this calculation provides an upper bound for the net revenue that potential entrants can receive in the equilibrium.

Table 9 summarizes the parameters used to perform the calculation. The last column reports the net revenue for each potential entrants. By comparing the net revenue to the annualized cost of entry estimated by ERCOT, it is clear that none of the potential entrants has a high enough net revenue to justify new investment in equilibrium.

Table 9: Net Revenue Analysis of New Thermal Technologies

Potential Entrant Technology	Heat Rate $(\frac{\text{mmbtu}}{\text{MWh}})$	Variable o&m ($/MWh)	Cost of Entry ($/kW-y)	Net Revenue ($/kW-y)
Coal	9.5	5	210-270	15.6-38.5
Natural Gas (Combined Cycle)	7	4	105-135	18.6-41.5
Natural Gas (Combustion Turbine)	10.5	4	80-105	7.8-30.7

Note: The estimates on heat rate, variable o&m costs, and cost of entry are obtained from ERCOT's 2012 State of the Market Report. Available at https://www.potomaceconomics.com/uploads/ercot_reports/2012_ERCOT_SOM_REPORT.pdf. Each technology has a range of net revenue, which depends on the location (West, South, Houston, or North) that the investment is assumed to occur.

7.4. Implications for the national variable subsidies

The results from the previous section suggest that welfare gain from subsidy differentiation depend on the correlation between wind resources productivity and the marginal emissions across regions. This subsection examines this correlation across different regions in the U.S. and discusses the implications of the national optimal variable subsidies, i.e. allowing the federal renewable subsidy rates to differ across interconnection regions in the U.S.

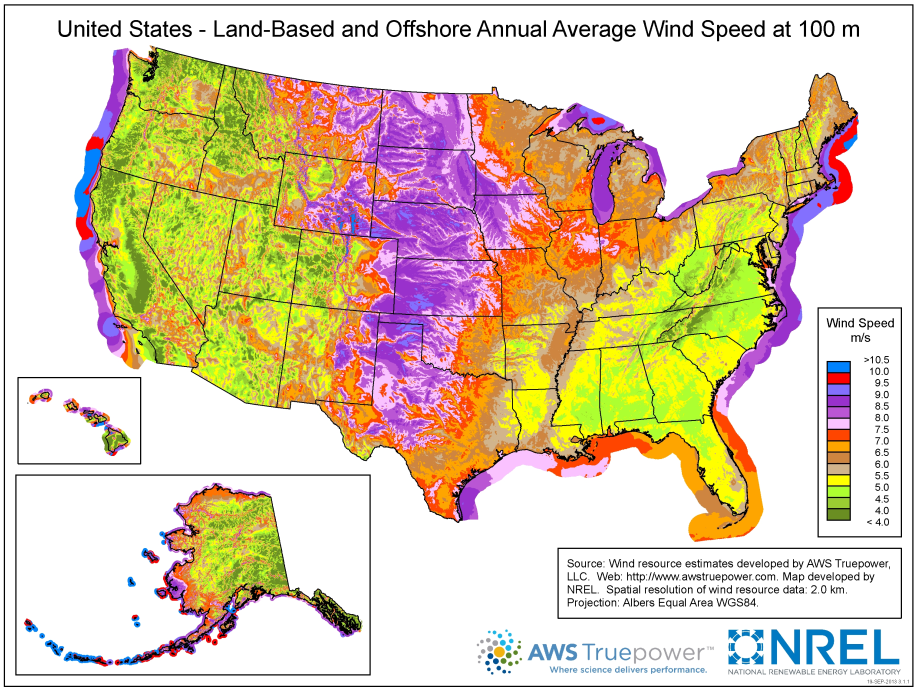
Figure 9a reveals that among all the NERC interconnections, ERCOT has the best wind resources potential followed by the Eastern and the Western Interconnection respectively.[20] On the other hand, figure 9b from Graff Zivin et al. (2014) suggests that the marginal emissions (i.e. the environmental benefits) is highest in the Eastern interconnection, followed by ERCOT and the Western Interconnection. Thus, there is a negative correlation between the wind resources potential and the marginal emissions at the national level similar to what is observed in ERCOT.

The national optimal variable subsidies will attract more investment into the Eastern interconnection and less investment into ERCOT. However, since the wind resources potential in the Eastern interconnection is not as productive, new investment in the Eastern interconnection would have to increase to more than offset the reduction in investment in ERCOT (relative to the uniform subsidy case). This mechanism increases the overall cost of investment and will compromise some of the additional environmental benefits from differentiating the subsidies. Thus, even if the the optimal variable subsidies are implemented at the national level, we should not expect a much larger gain from subsidy differentiation than what is predicted for the ERCOT region.

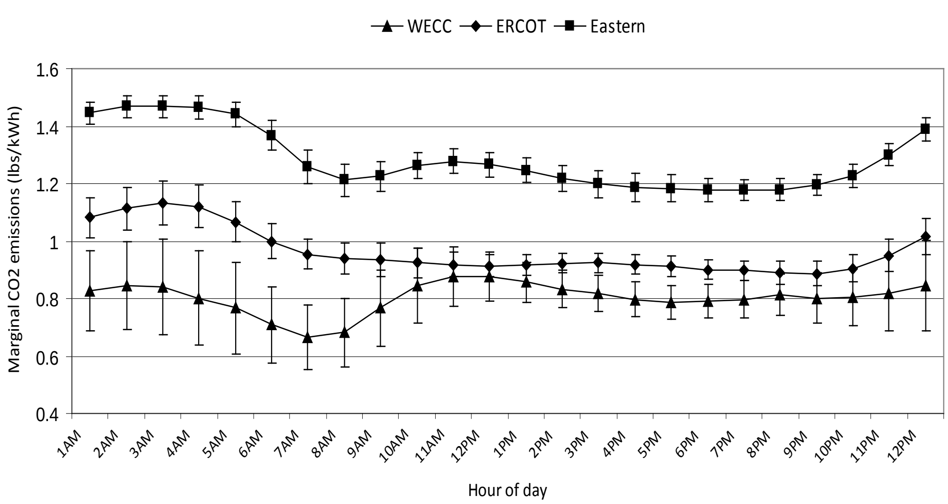
[20]Definitions for the NERC interconnections can be found here: http://www.nerc.com/AboutNERC/keyplayers/Documents/NERC_Interconnections_Color_072512.jpg.

Figure 9

(a) Annual Average Wind Resource Potential at 100m height. Source: http://www.nrel.gov/gis/wind.html.



(b) Average marginal emissions of CO_2 by interconnection. Source: Graff Zivin et al. (2014).



8. Conclusion

This paper assesses the welfare performance of differentiating renewable energy subsidies in the presence of heterogeneous market values and environmental values across location and time. I compare the welfare gain from the optimal variable subsidies to those of the status quo uniform subsidy and the optimal emissions tax. On one hand, the optimal variable subsidies have potential to coordinate renewable investment in a socially optimal manner compared to the status quo subsidy. One the other hand, implementing such complicated variable subsidies would require non-trivial administrative and information costs.

I find that despite a non-trivial spatial variation in the environmental benefits across regions in ERCOT, differentiating renewable subsidies does not increase welfare by much. In fact, most of the welfare gain from the optimal variable subsidies come from its ability to induce the right *level* of investment and not from its ability to attract new investment to the right location. The benefit of differentiation is small because of the characteristic of the Texas market, in which the productivity of wind resource is negatively correlated with its environmental value. This negative correlation makes it costly to shift new investment into areas with higher environmental value.

In addition, I find that the optimal emissions tax delivers a substantially larger welfare gain than both types of renewable subsidies. The large welfare advantage of the emissions tax over the renewable energy subsidies comes from its ability to induce additional low-cost emissions abatement through demand conservation and cross-plant fuel substitution.

Together, the empirical results in this paper suggest that there is much larger welfare to be gained from policies that stimulate demand conservation and cross-plant fuel substitution than those that optimize the patterns of renewable capacity investment.

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Appendix A. Social welfare decomposition

Without loss of generality, assume that demand curve, incumbent's aggregate marginal cost curve and aggregate emission curve can be approximated by a smooth, differentiable functions $P(q)$, $mc(q)$, and $e(q)$, respectively.

Denote equilibrium electricity production by conventional thermal and wind units in each hour by Q_{dh}^{conv} and Q_{dh}^{wind}, respectively. The total electricity produced in each hour is then $Q_{dh}^{*} = Q_{dh}^{conv} + Q_{dh}^{wind}$. Lastly, let τ be CO_2 emissions tax per MWh, s be renewable subsidy per MWh, c be the marginal social cost (per ton) of $CO2$ emissions.[21]

Net consumer surplus is calculated as

$$CS = \int_0^{Q_{dh}^{*}} P(q)dq - p_{hd}^{*} \cdot Q_{dh}^{*}.$$

Producer surplus for thermal generation resources is defined as

$$PS_{conv} = p_{dh}^{*} Q_{dh}^{conv} - \int_0^{Q_{dh}^{conv}} (mc_{dh}(q) - c \cdot e_{dh}(q))dq.$$

Producer surplus for wind generation resource is defined as

$$PS_{wind} = (p_{dh}^{*} + s) Q_{dh}^{wind}.$$

Government transfers in the forms of revenue collected from emission tax and the expenditure to subsidize renewable electricity production are calculated as

$$\text{tax revenue:} \quad taxRev = \int_0^{Q_{dh}^{conv}} \tau \cdot e_{dh}(q)dq,$$

$$\text{subsidy cost:} \quad subsidyCost = s \cdot Q_{dh}^{wind}.$$

For simplicity, I assume that the revenue from tax (expenditure for subsidy) is returned (deducted) to consumers in a lump-sum fashion.

[21] The estimates for c is obtained from Interagency Working Group on Social Cost of Carbon (2013).

External cost of emissions in the form of social cost of $CO2$ emissions from electricity generation is

$$Ecost = \int_0^{Q_{dh}^{conv}} c \cdot e_{dh}(q)dq.$$

Investment cost includes equipment cost, land rent, interest on loans, interconnection, and feasibility assessment costs. The total investment cost for new wind generation capacity is

$$InvCost(K) = FC^w \cdot K.$$

Taken together, the **discounted net social benefit** over the 20-year time span can be expressed as

$$W(K) = \sum_{y=1}^{20} \sum_{d,h} \int_0^{Q^*(K)} \frac{[P(q) - mc(q) - c \cdot e(q)]dq}{(1+r)^y} - FC^w \cdot K. \tag{A.1}$$

Appendix B. Optimal emissions tax and subsidies

Appendix B.1. Derivation of the long-run optimal emissions tax

In the following expressions, I drop subscripts for year, day, and hour to simplify notations. Using equation (A.1), rewrite the long-run discounted net social benefit under emissions tax as a function of renewable output and capacities across all congestion zones as

$$W_{tax} = \sum_{y,d,h}^{20} \sum_{z=1}^{4} \frac{\int_0^{Q^*_{z,tax}(K_z)} [P_z(q) - mc_z^{tax}(q - x^w(K_z)) - ce_z^{tax}(q - x^w(K_z))]dq}{(1+r)^y} - FC^w \cdot K_z. \tag{B.1}$$

Consider the social planner's problem whose the objective is to choose *zone-specific* renewable capacity investment to maximize the net social benefit. The corresponding first-order condition is:

$$\sum_{y=1}^{20} \sum_{d,h} \left[P(Q^*_{ydh}) - mc^{tax}(Q^*_{ydh} - x^w(K)) - ce^{tax}(Q^*_{ydh} - x^w(K))\right] \frac{\partial Q^*}{\partial x^w(K)} \frac{\partial x^w(K)}{\partial K}$$
$$+ \sum_{y=1}^{20} \sum_{d,h} \left[mc^{tax}(Q^*_{ydh} - x^w(K)) + ce^{tax}(Q^*_{ydh} - x^w(K)\right] \frac{\partial x^w(K)}{\partial K} = FC^w.$$

By setting the emissions tax equal to the social cost of carbon, i.e. $\tau = c$, the first term disappears because electricity price needs to equate the marginal cost of production *plus* tax payment of the most expensive thermal unit in the short-run market. This leaves the long-run optimality condition under optimal emissions tax in zone z to be

$$\frac{\partial W_{tax}}{\partial K_z} = \sum_{y,d,h}^{20} \frac{mc^{tax}(Q^*_{z,ydh} - x^w(K_z)) + ce^{tax}(Q^*_{z,ydh} - x^w(K_z))}{(1+r)^y} \frac{\partial x^w(K_z)}{\partial K_z} = FC^w$$

By comparing the above social planner's first-order condition to that of the private investment problem in (2), we can see that it is optimal to compensate entering renewable capacities with a rate that reflects the avoided marginal production and emission costs of the last thermal generation unit producing in each hour and location. Using notations from equation (2),

$$mc_z^{tax}(Q^*_{z,ydh} - x^w(K_z)) + ce_z^{tax}(Q^*_{z,ydh} - x^w(K_z)) = p^*_{z,ydh}.$$

This implies taxing emissions at rates equal to their social costs, $\tau = c$ is socially optimal both in the short and long run.

Appendix B.2. Derivation of the long-run optimal variable subsidies

Rewrite the long-run discounted net social benefit under renewable subsidy policy as a function of renewable output and capacities across all congestion zones as

$$W_{sub} = \sum_{y,d,h}^{20} \sum_{z=1}^{4} \frac{\int_0^{Q^*_{z,sub}(K_z)} [P_z(q) - mc_z^{sub}(q - x^w(K_z)) - ce_z^{sub}(q - x^w(K_z))]dq}{(1+r)^y} - FC^w \cdot K_z. \tag{B.2}$$

The first-order condition for the long-run social planner problem under variable subsidy is:

$$\sum_{y=1}^{20} \sum_{d,h} \left[P(Q^*_{ydh}) - mc_{sub}(Q^*_{ydh} - x^w(K)) - ce_{sub}(Q^*_{ydh} - x^w(K))\right] \frac{\partial Q^*}{\partial x^w(K)} \frac{\partial x^w(K)}{\partial K}$$
$$+ \sum_{y=1}^{20} \sum_{d,h} \left[mc_{sub}(Q^*_{ydh} - x^w(K)) - ce_{sub}(Q^*_{ydh} - x^w(K)\right] \frac{\partial x^w(K)}{\partial K} = FC^w.$$

Since $P(Q^*_{ydh}) - mc_{sub}(Q^*_{ydh} - x^w(K)) = 0$ at the market equilibrium, the expression simplifies to:

$$\sum_{y=1}^{20} \sum_{d,h} \frac{mc_{sub}(Q^*_{ydh} - x^w(K)) + ce_{sub}(Q^*_{ydh} - x^w(K)) \cdot (1 - \frac{\partial Q^*_{ydh}}{\partial x^w(K)})}{(1+r)^y} \cdot \frac{\partial x^w(K)}{\partial K} = FC^w.$$

The first-order condition from private investment problem (2) suggests that it is optimal to compensate each renewable entrant at a rate equals to the market price plus an *explicit* production subsidy. This optimal production subsidy is equal to the avoided environmental cost of the marginal thermal unit *scaled down* by the factor of $1 - \frac{\partial Q^*_{z,ydh}}{\partial x^w(K_z)}$ to reflect the fact that wind entry suppresses electricity prices and increases overall demand,[22]. In notations of equation (2).

$$mc_z^{sub}(Q^*_{z,ydh} - x_w(K_z)) = p^*_{z,ydh},$$
$$ce_z^{sub}(Q^*_{z,ydh} - x_w(K_z)) \cdot (1 - \frac{-mc'_z}{P' - mc'_z}) = s_{z,ydh}.$$

In the case of perfectly inelastic demand (P' is infinite), the scaling factor disappears and the optimal subsidy is simply the environmental cost of the marginal thermal unit producing in each hour. Further, if no transmission constraint binds, the market price and the optimal

[22] Applying the implicit function theorem at the market equilibrium $P(Q^*_{z,ydh}) = mc_z^{sub}(Q^*_{z,ydh} - x^w(K_z))$, we find that $\frac{\partial Q^*_{z,ydh}}{\partial x^w(K_z)} = \frac{-mc'_z(Q^*_{z,ydh} - x^w(K_z))}{P'(Q^*_{z,ydh}) - mc'_z(Q^*_{z,ydh} - x^w(K_z))}$

renewable subsidy are the same across locations and the subscript z is dropped. If any of the transmission constraints binds, the market price and the optimal renewable subsidy can differ across locations, hence the name "variable subsidy."

Appendix C. Welfare decomposition, central case with 2008 natural gas price

Variable	Unreg. Baseline	Emission Tax	Status Quo	Variable Subsidy	Var Sub Margin
Social cost of carbon (scc): $5/ton					
Δ Welfare ($ M)	0.0	13.7	-66.5	2.5	103.8
Δ Producer Surplus ($ M)	0.0	852.0	-122.6	0.6	
Δ Consumer Surplus ($ M)	0.0	-808.8	442.4	30.4	
Δ Emission Cost ($ M)	0.0	-12.3	-18.5	-1.3	
Δ Wind Investment Cost($ M)	0.0	41.8	404.7	29.8	
Social cost of carbon (scc): $21/ton					
Δ Welfare ($ M)	0.0	153.5	-7.2	24.9	446.8
Δ Producer Surplus ($ M)	0.0	3,407.7	-122.6	-25.1	
Δ Consumer Surplus ($ M)	0.0	-3,288.6	442.4	182.5	
Δ Emission Cost ($ M)	0.0	-252.0	-77.8	-33.4	
Δ Wind Investment Cost($ M)	0.0	217.6	404.7	165.9	
Social cost of carbon (scc): $35/ton					
Δ Welfare ($ M)	0.0	405.9	44.7	56.8	27.1
Δ Producer Surplus ($ M)	0.0	5,377.6	-122.6	-62.0	
Δ Consumer Surplus ($ M)	0.0	-5,454.1	442.4	307.9	
Δ Emission Cost ($ M)	0.0	-817.3	-129.7	-92.8	
Δ Wind Investment Cost($ M)	0.0	334.9	404.7	281.9	
Social cost of carbon (scc): $40/ton					
Δ Welfare ($ M)	0.0	526.1	63.2	71.1	12.5
Δ Producer Surplus ($ M)	0.0	6,036.1	-122.6	-73.6	
Δ Consumer Surplus ($ M)	0.0	-6,223.3	442.4	342.4	
Δ Emission Cost ($ M)	0.0	-1,079.0	-148.2	-117.4	
Δ Wind Investment Cost($ M)	0.0	365.7	404.7	315.0	
Social cost of carbon (scc): $55/ton					
Δ Welfare ($ M)	0.0	998.1	118.8	122.3	2.9
Δ Producer Surplus ($ M)	0.0	7,754.7	-122.6	-108.1	
Δ Consumer Surplus ($ M)	0.0	-8,482.2	442.4	438.1	
Δ Emission Cost ($ M)	0.0	-2,167.2	-203.8	-204.0	
Δ Wind Investment Cost($ M)	0.0	441.6	404.7	411.8	
Social cost of carbon (scc): $60/ton					
Δ Welfare ($ M)	0.0	1,196.1	137.3	141.8	3.2
Δ Producer Surplus ($ M)	0.0	8,265.2	-122.6	-117.3	
Δ Consumer Surplus ($ M)	0.0	-9,195.8	442.4	464.3	
Δ Emission Cost ($ M)	0.0	-2,591.5	-222.3	-235.7	
Δ Wind Investment Cost($ M)	0.0	464.8	404.7	440.9	

Note: All the figures represent changes in welfare and its components from the unregulated baseline. Δ Welfare = Δ PS + Δ CS - Δ Emissions Cost - Δ Wind Investment Cost. *Var Sub Margin* denotes the welfare advantage of the optimal variable subsidies over the status quo subsidy, express as a percentage of the welfare gain under the status quo subsidy.

Appendix D. Welfare decomposition, central case with 2012 natural gas price

Variable	Unreg. Baseline	Emission Tax	Status Quo	Variable Subsidy	Var Sub Margin
Social cost of carbon (scc): $5/ton					
Δ Welfare ($ M)	0.0	11.4	-43.1	0.0	100.0
Δ Producer Surplus ($ M)	0.0	1,021.2	41.3	0.0	
Δ Consumer Surplus ($ M)	0.0	-1,032.8	29.8	0.0	
Δ Emission Cost ($ M)	0.0	-23.0	-8.9	0.0	
Δ Wind Investment Cost($ M)	0.0	0.0	123.1	0.0	
Social cost of carbon (scc): $21/ton					
Δ Welfare ($ M)	0.0	220.1	-14.6	0.0	100.0
Δ Producer Surplus ($ M)	0.0	3,993.9	41.3	-0.0	
Δ Consumer Surplus ($ M)	0.0	-4,220.7	29.8	0.0	
Δ Emission Cost ($ M)	0.0	-447.0	-37.5	-0.0	
Δ Wind Investment Cost($ M)	0.0	0.0	123.1	0.0	
Social cost of carbon (scc): $35/ton					
Δ Welfare ($ M)	0.0	586.4	10.4	10.4	0.4
Δ Producer Surplus ($ M)	0.0	6,246.5	41.3	43.0	
Δ Consumer Surplus ($ M)	0.0	-6,670.1	29.8	31.5	
Δ Emission Cost ($ M)	0.0	-1,105.0	-62.4	-65.5	
Δ Wind Investment Cost($ M)	0.0	95.1	123.1	129.6	
Social cost of carbon (scc): $40/ton					
Δ Welfare ($ M)	0.0	748.2	19.3	21.4	11.1
Δ Producer Surplus ($ M)	0.0	6,970.8	41.3	52.5	
Δ Consumer Surplus ($ M)	0.0	-7,470.5	29.8	43.8	
Δ Emission Cost ($ M)	0.0	-1,390.3	-71.3	-97.2	
Δ Wind Investment Cost($ M)	0.0	142.3	123.1	172.1	
Social cost of carbon (scc): $55/ton					
Δ Welfare ($ M)	0.0	1,310.0	46.1	69.5	50.9
Δ Producer Surplus ($ M)	0.0	8,957.8	41.3	66.6	
Δ Consumer Surplus ($ M)	0.0	-9,743.0	29.8	78.0	
Δ Emission Cost ($ M)	0.0	-2,326.9	-98.1	-203.2	
Δ Wind Investment Cost($ M)	0.0	231.7	123.1	278.3	
Social cost of carbon (scc): $60/ton					
Δ Welfare ($ M)	0.0	1,518.5	55.0	89.5	62.8
Δ Producer Surplus ($ M)	0.0	9,562.6	41.3	69.0	
Δ Consumer Surplus ($ M)	0.0	-10,463.8	29.8	91.0	
Δ Emission Cost ($ M)	0.0	-2,671.9	-107.0	-245.8	
Δ Wind Investment Cost($ M)	0.0	252.3	123.1	316.3	

Note: All the figures represent changes in welfare and its components from the unregulated baseline. Δ Welfare = Δ PS + Δ CS - Δ Emissions Cost - Δ Wind Investment Cost. *Var Sub Margin* denotes the welfare advantage of the optimal variable subsidies over the status quo subsidy, express as a percentage of the welfare gain under the status quo subsidy.

Appendix E. Slope and intercept from wind resource curve estimation

Hour	West		South		North	
	Slope	Intercept (x10^{-4})	Slope	Intercept(x10^{-4})	Slope	Intercept (x10^{-4})
0	0.63769	-0.858690	0.34554	-2.744210	0.51766	-9.10739
	(0.17279)	(6.10816)	(0.07116)	(0.75853)	(0.08285)	(0.14469)
1	0.64494	-0.876931	0.32988	-2.629161	0.52589	-9.63983
	(0.16168)	(5.58895)	(0.06467)	(0.72246)	(0.08151)	(0.13762)
2	0.64383	-0.879122	0.31314	-2.571992	0.52513	-9.72809
	(0.17285)	(6.03733)	(0.06609)	(0.64983)	(0.08240)	(0.13176)
3	0.63511	-0.870483	0.29638	-2.467373	0.51946	-9.99294
	(0.16191)	(5.52574)	(0.06774)	(0.66190)	(0.08480)	(0.13103)
4	0.62210	-0.857124	0.28087	-2.298924	0.50829	-9.91880
	(0.17117)	(5.72956)	(0.06514)	(0.59020)	(0.08776)	(0.13315)
5	0.60844	-0.842065	0.27432	-2.218585	0.49494	-9.75357
	(0.16821)	(5.40492)	(0.06602)	(0.58445)	(0.08955)	(0.13392)
6	0.59111	-0.818006	0.26521	-2.127216	0.48074	-9.46765
	(0.17460)	(5.44754)	(0.06760)	(0.61476)	(0.09187)	(0.13610)
7	0.56933	-0.790457	0.25801	-2.091267	0.45875	-9.07454
	(0.17899)	(5.17861)	(0.07062)	(0.68553)	(0.09924)	(0.14399)
8	0.54393	-0.747178	0.26010	-2.043978	0.43386	-8.64555
	(0.18406)	(5.64261)	(0.07400)	(0.79782)	(0.10241)	(0.14967)
9	0.51045	-0.700059	0.27430	-2.088329	0.38845	-7.56164
	(0.16715)	(5.05225)	(0.07329)	(0.73017)	(0.10429)	(0.14930)
10	0.47911	-0.6537810	0.29883	-2.2992610	0.35005	-6.71517
	(0.15359)	(4.81202)	(0.07312)	(0.68499)	(0.10614)	(0.14741)
11	0.45808	-0.6247311	0.31758	-2.4458211	0.33407	-6.32046
	(0.15058)	(4.59074)	(0.07502)	(0.66540)	(0.10977)	(0.15527)
12	0.43987	-0.5996312	0.33290	-2.5193212	0.32226	-5.90339
	(0.14642)	(4.30350)	(0.06888)	(0.63295)	(0.10967)	(0.15416)
13	0.42392	-0.5708013	0.36167	-2.7274613	0.32069	-5.81455
	(0.14815)	(4.17624)	(0.06976)	(0.65352)	(0.11184)	(0.15112)
14	0.41451	-0.5510414	0.39900	-3.0096714	0.32057	-5.62772
	(0.15133)	(4.53761)	(0.08205)	(0.73659)	(0.11311)	(0.14954)
15	0.41202	-0.5423215	0.43466	-3.2977015	0.32479	-5.64394
	(0.14795)	(4.47504)	(0.09616)	(0.82915)	(0.11336)	(0.14637)
16	0.41438	-0.5410816	0.45610	-3.4305116	0.33136	-5.85956
	(0.14131)	(4.32561)	(0.11320)	(1.03023)	(0.11116)	(0.14244)
17	0.41978	-0.5501017	0.46270	-3.5561717	0.32853	-5.63421
	(0.13472)	(4.42619)	(0.12418)	(1.09563)	(0.10600)	(0.13390)
18	0.43360	-0.5710818	0.45308	-3.5688418	0.33966	-5.76959
	(0.14099)	(4.48968)	(0.12969)	(1.26410)	(0.09893)	(0.12481)
19	0.46965	-0.6193519	0.43827	-3.5208219	0.37576	-6.30194
	(0.15091)	(4.70743)	(0.11954)	(1.25674)	(0.09340)	(0.11595)
20	0.51490	-0.6812920	0.41310	-3.3069820	0.42032	-7.06153
	(0.17401)	(5.74907)	(0.11127)	(1.28969)	(0.09103)	(0.12851)
21	0.55759	-0.7385021	0.39372	-3.1933321	0.44667	-7.29887
	(0.17464)	(6.03466)	(0.09492)	(1.15174)	(0.09065)	(0.13854)
22	0.59845	-0.7990522	0.37224	-3.0065622	0.48327	-8.28229
	(0.16970)	(5.95321)	(0.08091)	(0.98868)	(0.09024)	(0.15172)
23	0.62714	-0.8414823	0.35979	-2.8862023	0.50792	-8.96793
	(0.17651)	(6.30493)	(0.07346)	(0.84311)	(0.08657)	(0.14985)

Note: The table shows the slopes and intercepts for the hourly marginal wind output according to equation eq:marginalWind. The equation is estimated separately for the 3 regions with adequate wind resource —West (W), South (S), and North (N)