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Building Blocks: Investment in Renewable and Non-Renewable Technologies

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1. Introduction

Within a span of 20 years, the electric power industry has become the central focus of two extraordinary policy trends, each one significant enough to fundamentally reshape the industry. One of these trends is liberalization, a term that has come to encompass both privatization and regulatory restructuring. Beginning with the visions articulated in such works as Joskow and Schmalansee (1985) and Schweppe et al. (1988), the restructuring movement in electricity can be viewed as an extension of the trend toward market liberalization that had previously transformed the airline, communications, and natural gas industries. The generation sector of the industry has undergone a sporadic but inexorable transition from economic regulation under cost-of-service principles to an environment in which markets heavily influence, if not dominate, the remuneration and investment decisions of firms.

The second trend to engulf the electricity industry has been the growth of the environmental movement. More specifically, the growing alarm over the threat of global climate change, and the more recent engagement of policymakers in combating it, is likely to dominate decision making in the power industry over the next several decades. Electricity and heat production are responsible for 40% of CO_2 emissions in the United States and about 31% worldwide (Stern 2006).

Although not obvious at first glance, these two trends, restructuring and environmental regulation, share many common ideological roots. In the United States, the growing stringency in air quality regulation was accompanied by an increased acceptance of market-based environmental regulations. These include cap-and-trade mechanisms, such as the program put in place to limit SO_2 emissions under the 1990 amendments to the Clean Air Act (Ellerman et al. 2000). Regulators were also interested in experimenting with market-based incentives to promote alternative energy sources. Many trace the birth of the U.S. independent power industry to the passage of the Public Utilities Regulatory Policies Act (PURPA) in 1978. The PURPA legislation established mandates for the purchase of energy produced by qualifying small and renewable sources of generation (Joskow 1997; Kahn 1988). Although inspired largely by environmental and energy security goals, the largest impact of PURPA is arguably in the resulting demonstration of the viability of smaller-capacity generation technologies and the nonutility generator business model.

One important aspect of the independent power producer business model was the relative freedom—and risk—allowed in investment of new facilities. Investments are based on market-based long-term contracts and projections of market revenues, rather than regulatory findings of need and guaranteed cost recovery. The restructuring movement in the United States was led by states with the worst track records in utility investment (Ando and Palmer 1998). Although evidence suggests that operations have become more efficient in these states (Wolfram 2005), restructuring was primarily intended to improve the incentives of firms to make prudent investments (Borenstein and Bushnell 2000). In some parts of the world, this general approach to investment has come to dominate the industry. In many others, policymakers continue to search for the proper tools for balancing market incentives with concerns over reliability and adequacy of investment (Joskow 2005; Oren 2005). One central aspect of this search concerns the design of wholesale electricity markets and the payment streams they provide to suppliers. Markets can differ greatly on the primary sources of remuneration for generators, with some relying on energy and ancillary services markets, while others have established mechanisms for compensating suppliers for their installed or available capacity (Bushnell 2005; Cramton and Stoft 2005).

This chapter studies the intersection of these two trends as they come to dominate the economics of the industry. In particular, it examines how the increasing penetration of intermittent renewable generation can change the economic landscape for merchant power investment in conventional thermal generation. Currently, renewable generation earns revenues from a wide range of sources, from energy markets to government tax credits. The impact of renewable generation on the electricity markets in which they participate has to date been relatively modest outside of regions of high concentration such as west Texas. That will almost certainly change, however, as state and federal policies considerably ramp up the amount of renewable generation throughout the country. This can have a profound impact on prices and the economics of supply for both renewable and nonrenewable generation.

An equilibrium model of generation investment is developed, based on the long-standing principles of finding the optimal mix of capital intensive and higher marginal cost resources to serve a market with fluctuating demand. This model is then applied to data on electricity markets from several regions of the western United States to examine how the interaction of increasing wind capacity and electricity market design affects the equilibrium mix of thermal capacity and the revenues earned by renewable suppliers. The chapter first provides a brief background on this question, then describes the equilibrium conditions that form the stylized investment model. Next, it details the data and assumptions used in the study. The final section contains the bulk of the results and analysis.

2. Background: Renewable Energy in Restructured Electricity Markets

Renewable, or green, power is viewed by many policymakers as the key to combating greenhouse gas emissions within the power sector. Explicit and implicit subsidies for renewable power continue to grow. By the end of 2007, 25 U.S. states and Washington, DC, had some form of renewable portfolio standard (RPS), which requires purchasers of wholesale electricity to procure some percentage of their power from renewable sources (Wiser and Barbose 2008). The long-standing, but intermittent and precarious, production tax credit (PTC) for wind energy in the United States pays wind producers 2.1 cents/kWh for energy production. The American Recovery and Reinvestment Act of 2009 contained several provisions favorable to renewable generation, including the extension of the PTC until 2012 and alternative investment tax credits for facilities constructed in 2009 and 2010 (Wiser and Bolinger 2009).

For the industry as a whole, the growth of nonutility generation has coincided with the expansion of renewable generation sources. This is not the product of happenstance; from the passage of PURPA, various legislative purchasing mandates and tax incentives played a dominant role in the growth of both renewable and nonutility generation. To this day, the renewable industry is dominated by nonutility producers.[1]

The subsidization of renewable generation is expanding in parallel with efforts to create cap-and-trade programs for CO_2. This can be seen as antithetical to the spirit of a cap-and-trade program, where promoting flexibility in compliance options is a central ideal. Unlike the SO_2 program, cap-and-trade is but one of a broad set of policy tools being brought to bear against greenhouse gas (GHG) emissions. Some view this as undermining the strength of cap-and-trade regulation. The cap has less incremental impact if much of the GHG reductions are already accounted for under various more directed measures and regulations. In regions such as California, cap-and-trade is viewed more as a backstop than as a bulwark in combating climate change.

Although policies that promote renewable generation sources are extremely popular with regulators, politicians, and the general public, their continued expansion to unprecedented levels does raise some concerns. One source of concern is cost. Although the technological frontier continues to advance, much controversy exists over the appropriate timing and form of policy intervention to promote renewable generation. Most accept that renewable generation would not be a significant source of supply today if not for some form of public support. The fact that the external cost of GHG emissions have not yet been priced into the investment decisions of fossil-based generation firms certainly provides justification for support of renewable power, but the prospect of regional and possibly national caps on CO_2 emissions undermines that justification. A common argument for support of renewable generation is the hope that expansion of supply will yield learning benefits, thereby lowering costs of future supply. However, a market failure exists only if that learning cannot be appropriated for private gain. Although the bulk of public support for renewable generation has taken the form of production mandates or credits, it is not clear whether commercialization is the point in the supply chain where the problem of intellectual property is most acute. Further, the evidence to date indicates that cost reductions in alternative energy sources can be driven as much by exogenous technology developments as by the expansion of installed capacity (Nemet 2006).

The most commonly heard concern over the rapid expansion of renewable electricity supply is over the fact that this supply is available only intermittently (NERC 2009). With the prospect of one-fifth or more of electrical energy coming from intermittent sources, many in the industry are confronting the fact that the traditional tools for planning for and providing reliable electric service may prove inadequate. In fact, as discussed below, the traditional utility planning paradigm has been disrupted by market liberalization over the last 10 years. The industry has yet to settle on a single framework to replace utility planning. The large-scale addition of intermittent resources is therefore happening against a backdrop in which the mechanisms through which generators are compensated are very much in flux.

3. Investment in Restructured Electricity Markets

Since the onset of market liberalization, concerns have been raised that the newly formed market regimes would fail to produce adequate investment in generation capacity. Ironically, in many parts of the world, it was the cost of excess capacity that provided the impetus for liberalization. The safety net of guaranteed capital cost recovery in both publicly owned and rate-of-return regulated utilities had provided a high degree of reliability. Indeed, the reliability of electric supply in most OECD countries is so high that it is often taken for granted. U.S. electricity consumers, unlike those in many developing countries, fully expect to be able to consume as much electricity as they need whenever they desire.

These high levels of reliability came at a high cost, however, particularly when combined with the weak incentives for cost control provided by public ownership and regulation. Under the traditional model, a utility and its regulators jointly forecast a “need” for investment, and the regulator would guarantee the recovery of costs undertaken to meet that need. In the liberalized market, private firms no longer receive a guaranteed recovery of their investments. One of the hopes for liberalization was that this market-based risk would lead to more prudent and cost-effective investment decisions. At the very least, it was observed, the costs of overinvestment would be borne by investors rather than ratepayers under the new market regime. In many markets, this latter belief has been supported by the fact that many of the firms that procured or expanded capacity in liberalized markets experienced severe financial difficulties during the early part of this decade.

Whereas a transition away from payments based on a cost-of-service framework is shared by all liberalized markets, the revenue streams that replaced these payments differ greatly. Many markets focus the remuneration of generators on the provision of energy and related services. In the jargon of the U.S. electricity industry, this conceptual framework has been referred to as an “energy-only” framework. The name, which is somewhat inaccurate, refers to the fact that contributions against fixed and sunk costs arise only from payments for the provision of either energy or associated operating reserve services. Although no market is fully unconstrained in this way, markets such as those found in the United Kingdom, Australia, Texas, New Zealand, and Norway operate under general energy-only principles to the extent that they have no or relatively high price caps and provide no other specific payments for the supply of capacity.

In many markets, however, the revenues provided from the provision of energy and ancillary services appear to be insufficient to cover the fixed cost of new entry (Joskow 2005). Myriad reasons can be given for this, including the existence of price caps, the subtle but significant impact of the decisions of system operators on market prices, and simply the over investment of capacity. This and other factors have led to a level of discomfort among many policymakers over leaving investment decisions entirely up to the market. Therefore, many electricity markets, including several in the United States, provide payments for capacity "availability" that supplement revenues received for the provision of energy and ancillary services. This feature is not unique to the United States, as capacity payments played a significant role in the early years of market liberalization in the United Kingdom and continue to be a significant factor in Spain and Colombia.

The details of these capacity payments vary, but the general common features that are represented in the stylized model used here are a formal or informal constraint on energy prices combined with a fixed payment (here assumed to be in dollars per megawatt-year) based on installed capacity. The fixed payments can be scaled according to the expected or historic availability of generation, a fact most significant for wind generation sources.

In many restructured markets, some form of payment for installed or available capacity is made to producers as a supplement to the revenues they earn through the sale of energy and ancillary services. These payments are not without controversy, however, as debate continues over how exactly to measure and remunerate the provision of "reliable" capacity (Cramton 2003; Hogan 2005; Oren 2005).

One aspect of this debate is how to deal with unconventional sources of generation. Resources, such as hydroelectric facilities, that are energy-limited cannot produce at their full capacity all the time. Many renewable resources can supply power only intermittently, and their supply is dependent on ambient conditions rather than under the control of the operator. In general, the capacity payments made to resources such as these are scaled downward according to rough probabilistic measures of their potential availability. As explored below, the specification of such rules will interact with the level of penetration of renewable generation to shift the relative value of different types of payment streams for intermittent producers.

The power industry today therefore features two contrasting models for financing new investment: the energy-only model, which relies on periodic, extremely high prices for energy and ancillary services to provide the scarcity rents that are applied to the recovery of capital costs; and the capacity payment model, in which a large portion of the capital costs are recovered through capacity payments. Under energy-only markets, the choice and profitability of specific generation sources will depend on the degree and timing of high prices. Under capacity markets, the spot energy prices are somewhat less critical, but the specific implementation of capacity payments is very important to the relative profitability of technologies.

The large-scale deployment of intermittent resources can imply a major paradigm shift for both investment models. Electric systems will likely experience a massive addition of renewable generation capacity that is largely motivated by nonmarket considerations such as climate change. This will result in an influx of energy with extremely low marginal cost, but only during some time periods. As a result, the remaining need for thermal generation capacity could look very different than it would in the absence of the renewable capacity. In market terms, the levels and patterns of energy prices could be quite different with the addition of renewables. The months and hours that experience peak prices will be driven as much by the availability of intermittent resources as by the fluctuations in end-use demand. These questions are explored empirically in the following section.

4. Equilibrium Model of Electricity Investment

This section uses a long-run equilibrium model of investment to explore the ramifications of greatly expanded intermittent supply. A technical formulation of the model is provided in the appendix at the end of this chapter. The model draws from the classic framework of utility investment, which applies a mix of technologies of varying capital intensity to satisfy fluctuating demand (see Kahn 1988). This demand is often represented in a load-duration curve, which illustrates a cumulative distribution of demand levels over some time period, such as one year. This basic model is expanded to incorporate elements of peak load pricing as articulated in theory by Borenstein (2005). The model examines the mix and cost of technologies that achieve the break-even point where annual energy revenues for each technology equal their annualized cost of capacity. As in Borenstein (2005), these values depend on prices rising above the marginal cost of the highest-cost technologies where, in effect, demand sets the market price. This process has come to be called "scarcity pricing" in wholesale electricity markets. Similar to Lamont (2008), the model also incorporates intermittent resources. As described below, the wind production profiles used here are based on specific projections of wind production profiles, rather than stylized correlation coefficients used by Lamont.

The model here assumes perfect competition, essentially free entry into any generation technology in the markets, and also disregard concerns of "lumpiness" of capacity. Firms are free to install any combination of capacity sizes that satisfy differentiable equilibrium conditions. This greatly simplifies computational concerns and, in light of the size of the markets being examined here, is not an unreasonable assumption. As this is a long-term model, it also ignores operational constraints such as minimum run times, start costs, and ramping rates. These are obviously important considerations of operating an electricity system that will be affected by the expansion of intermittent technologies, but they are beyond the capabilities of the model used here.

The approach of the model is to examine the actual load profiles or hourly distributions of demand of certain markets, and then impose varying levels of intermittent wind production on those demand distributions. In other words, the wind investment is considered exogenous to the equilibrium investment model, having been implemented through nonmarket constraints such as a renewable portfolio standard. The model then derives the mix of thermal technologies that would be constructed to serve the resulting residual demand that is left over after accounting for wind production. The equilibrium resulting from an assumption of competitive entry and no lumpiness is equivalent to the optimal, or least-cost, set of technologies. The intuition behind the equilibrium constraints described in the appendix is straightforward. Firms will continue to construct additional capacity in a given thermal technology as long as the revenues implied by the residual demand are sufficient to cover a levelized cost of investment, as well as operating costs.

The empirical calculations are based on data taken from the Western Electricity Coordinating Council (WECC) for the reference year 2007. These data are in turn subdivided into the four WECC subregions: the California (CA) region; the Northwest Power Pool (NWPP) region; the southwest (AZNM) region, made up mostly of Arizona and New Mexico; and the Rocky Mountain Power Pool (RMPP) region (see Figure 9.1).

Figure 9.1. The four WECC subregions

[INSERT FIGURE 9.1 HERE]

The general approach is to ask how electricity load would have looked during 2007 under various levels of wind penetration. The model then solves for the equilibrium investment mix of conventional technologies that optimally serves the resulting load shape. This section includes descriptions of the data sources and assumptions used in implementing this calculation.

It is important to keep in mind that this is not a simulation of the *incremental* investment required going forward in these markets, but rather an exercise that examines how the long-run equilibrium mix of generation and costs would change. Thus it is not meant to be predictive of these actual markets, but uses these market data to develop calculations for a range of possible representative markets. The market-based model assumes that all regions are restructured (when in fact, only California is currently even partially restructured) and that the investment choices are starting from a clean slate of no existing capacity.

One difficulty with simulating electricity markets in a high level of detail is that, although data on most fossil-fuel based generation units are quite extensive and reliable, far less data exist on the activities of hydroelectric plants, renewable generation, and the substantial amount of power generated from combined heat and power (CHP) or cogeneration plants. When building a counterfactual re-creation of an electricity market, these data gaps make assumptions about the missing production necessary.

This chapter takes the approach of restricting the construction of a counterfactual market outcome to the portion of resources for which detailed data are available. In effect, it assumes that, under the counterfactual assumptions of wind penetration, the operations of nonmodeled generation plants would not have changed. The total production from "clean" sources is unlikely to change in the short run. The production of electricity missing from the data is driven by natural resource availability (rain, wind, sun) or, in the case of CHP, to nonelectricity production decisions. The economics of production are such that these sources are essentially producing all the power they can. However, it is important to recognize that this modeling approach assumes that existing unconventional sources will not change not only *how much* they produce, but also *when* they produce it. This is a problematic assumption in regions with substantial hydro resources, such as the Pacific Northwest. Ideally, an investment analysis would involve a co-optimization of hydro, wind, and thermal electric production. This is beyond the scope of this chapter. For this reason, the results pertaining to the Pacific Northwest region should be interpreted with this shortcoming in mind.

In any event, the goal here is not to reproduce the electric system as it actually operated in 2007, but rather to assess how investment decisions would play out if the industry were starting from a completely clean slate and faced the residual (after existing unconventional generation) load shapes of 2007. The data used here are meant to convey conditions present in representative electricity systems, rather than completely reproduce a specific system.

4.1 Demand Data

The primary data source for this discussion is the BASECASE dataset from Platts, which is in turn derived primarily from the continuous emissions monitoring system (CEMS) used by the U.S. Environmental Protection Agency (EPA) to monitor the emissions of large stationary sources.[2] Almost all large fossil-fired electricity generation sources are included in this dataset, although hydroelectric, renewable, and some small fossil generation sources are missing. The CEMS reports hourly data on several aspects of production and emissions. Hourly data on nuclear generation plants are included with fossil generation data in the BASECASE dataset. The model here uses the hourly generation output and carbon emissions for available facilities. These hourly output data are aggregated by firm and region to develop the demand in the simulation model. As described above, this is in fact a residual demand: the demand that is left after applying the output from non-CEMS plants. Plant cost, capacity, and availability characteristics and regional fuel prices are then taken from the Platts POWERDAT dataset. These data are in turn derived from mandatory industry reporting to the Energy Information Administration (EIA) and North American Electric Reliability Council (NERC).

These data are then combined to create a demand profile and supply functions for periods in the simulation. Although hourly data are available, for computational reasons these are aggregated into representative time periods. Each of the four seasons has 50 such periods, yielding 200 explicitly modeled time periods. The aggregation of hourly data was based on a sorting of the California residual demand. California aggregate production was sorted into 50 bins based on equal MW spreads between the minimum and maximum production levels observed in the 2007 sample year. A time period in the simulation therefore is based on the mean of the relevant market data for all actual 2007 data that fall within the bounds of each bin. For example, every actual hour (of which there were 14) during spring 2007 in which California CEMS production fell between 7,040 and 7,243 MW were combined into a single representative hour for simulation purposes.

The number of season-hour observations in each bin is therefore unbalanced; there are relatively few observations in the highest and lowest production levels, and more closer to the median levels. The demand levels used in the simulation are then based on the mean production levels observed in each bin. In order to calculate aggregate production and revenues, the resulting outputs for each *simulated* demand level was multiplied by the number of *actual* market hours used to produce the input for that simulated demand level. Table 1 presents summary statistics of CEMS load levels for each of the four WECC subregions.

Table 1. Summary statistics of demand

	CEMS load (MW)			
Region	Mean	Min.	Max.	S.D.
CA	13,216	6,022	29,985	3,626
NWPP	15,334	9,670	18,884	2,400
AZNM	17,942	13,626	25,586	2,706
RMPP	6,986	5,531	9,141	723

Note: MW = megawatts; S.D. = standard deviation

4.2 Wind Generation Data

The wind generation profiles used in this chapter come from WECC transmission planning studies. The WECC studied several scenarios for renewable energy penetration (see Nickell 2008), with particular focus on an assumption of 15% of total WECC energy being provided from renewable sources. This modeling effort employed a dataset from the National Renewable Energy Laboratory (NREL) that provides 10-minute wind speeds with a high level of geographic resolution throughout the U.S. portion of the WECC system. The WECC study combines these wind potential data with other local sources of information to construct projections of new wind development, as well as of hourly wind production from those potential new sources.

This chapter draws on the hourly load profiles of the projected wind facilities from the WECC study and aggregates these profiles according to the four WECC subregions described above. Because of the focus here on the investment impacts of wind penetration, this section looks at the baseline level of estimated production used in the WECC study and also a level that is double that used in the WECC study. The aggregate generation levels are summarized in Table 2. As a portion of CEMS load, the new wind sources would account for about 15% of 2007 CEMS energy, although these resources are not evenly distributed across the WECC.[3] The RMPP area, which includes the wind-rich areas of Wyoming, has a great deal of wind potential, whereas the desert Southwest has much less.

Table 2. Aggregate generation levels

	Hourly averages				
Region	Load (MWh)	Wind (MWh)	Share	High wind (MWh)	Share
CA	13,216	1,866	14%	3,733	28%
NWPP	15,334	2,229	15%	4,458	29%
AZNM	17,942	1,445	8%	2,891	16%
RMPP	6,986	1,902	27%	3,804	54%
Totals	53,479	7,443	14%	14,885	28%

Note: MWh = megawatt-hours

When the projected additional wind production is combined with and assumed to displace CEMS production, the result is a sharply shifted residual load profile that must be served by conventional generation sources. Figures 2 and 3 illustrate the hourly CEMS load, both before and after accounting for the additional wind resources for the months of September and December.

Figure 2. CEMS load and wind production for July

[INSERT FIGURE 2 HERE]

Figure 3. CEMS load and wind production for December

[INSERT FIGURE 3 HERE]

The aggregate effects are well summarized by load duration curves presenting the cumulative distribution of CEMS load and residual demand after new wind sources. Figure 4 presents these load duration curves for the four subregions.

Figure 4. Annual distribution of CEMS load net of wind

[INSERT FIGURE 4 HERE]

The CEMS load profile in California is much more variable than in other regions, while CEMS load levels in the Pacific Northwest are relatively constant because of the abundance of hydro energy in that region. In all cases, the increasing penetration of wind resources makes the load profiles steeper. This reflects the fact that wind production is not correlated with CEMS load. To the extent that more wind production is generated in low CEMS load hours, the residual load becomes more variable and the load duration curve steeper. This effect is most pronounced in the RMPP region, where CEMS load was relatively constant but which experiences the highest degree of wind penetration.

The market implications of Figure 4 are central to the results of this chapter, so they deserve a little further discussion. The increasing penetration of wind resources in the WECC will create a surge of energy supply, much of which will be uncorrelated with end-use demand. The net result is a residual load shape that is more “peaky.” As will be demonstrated in the results of the simulations, the optimal mix of resources to serve this profile of residual demand will be composed of a far greater share of low-capacity-cost, high-marginal-cost peaking resources.

4.3 Thermal Generation Cost Data

The model here examines the optimal possible mix of generation technologies, assuming it starts from a clean slate, with no sunk (or stranded) investment decisions. This section examines the optimal mix of three basic technologies that form the backbone of most U.S. electric systems. Each represents different levels of the trade-off between capital costs and marginal costs. Included are a base load pulverized coal technology, a midmerit combined cycle gas turbine (CCGT) technology, and a peaking gas combustion turbine (CT). The costs of construction and operation for each of these technologies are taken from the Energy Information Administration’s 2007 annual energy outlook (EIA 2007). The basic cost characteristics, taken from the EIA study, are summarized in Table 3. To convert these costs to an annualized fixed cost, a 15-year payback period and 10% financing cost are assumed. Fuel costs are taken from the EIA’s figures for 2007. The resulting aggregate (including operating and maintenance) costs are summarized in Table 4.

Table 3. Thermal generation costs from EIA

	Total overnight cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)	HR Btu/kWh
Scrubbed new coal	2,058	27.53	4.59	9,200
CCGT	962	12.48	2.07	7,200
CT	670	12.11	3.57	10,800

Source: EIA 2007

Notes: O&M = operating and maintenance costs; HR = Heat Rate

Table 4. Thermal generation costs used in simulations

	Total annual fixed cost ($/kWy)	Fuel costs ($/MMBtu)	Total marginal cost ($/MWh)
Coal	282.17	1.74	20.60
CCGT	136.57	7.06	52.90
CT	98.51	7.06	79.82

Note: kWy = kilowatt-year

5. Analysis and Results

Using the data described in the previous section, the resulting optimal mix and level of generation capacity are calculated for each of the four WECC subregions. For the purposes of this study, each region is treated as isolated from the others. This is equivalent to assuming that transmission flows among the regions do not change from their 2007 levels. As described above, the four regions represent a wide spectrum in terms of current demand for generation and future wind potential.

5.1 Energy-Only Market

The results are first examined under an assumption that each region operates under an energy-only market paradigm, with no price cap and no capacity payments. The analysis begins with the equilibrium energy prices in each market. Figures 5 and 6 illustrate the hourly market-clearing energy prices in each market for the final week of August and first week of December. Note that these prices are plotted on a logarithmic scale, reflecting the highly volatile nature of equilibrium electricity prices in an energy-only market. Although significant differences in energy prices are difficult to detect in CA, the impact of wind penetration is clear on the pricing patterns in regions such as the NWPP and RMPP.

Figure 5. Energy market prices for August

[INSERT FIGURE 5 HERE]

Figure 6. Energy market prices for December

[INSERT FIGURE 6 HERE]

The changes in the residual demand profiles and the resulting equilibrium prices do have a significant effect. Figure 7 summarizes the equilibrium investment levels under three wind scenarios: wind at 2007 levels, wind at 14% of CEMS load, and wind at 28% of CEMS load.

Figure 7. Equilibrium capacity for energy-only market

[INSERT FIGURE 7 HERE]

Several aspects of the results are reflected in Figure 7. First, the already volatile CA load profile implies an optimal mix of relatively little base load generation compared with the other regions, whereas the very consistent load of the NWPP implies an optimal mix that is heavily base load, with no peaking resources at all under the baseline scenario. Second, the increasing penetration of wind resources produces a clear shift of investment toward less capital-intensive peaking resources in every market. This shift is most pronounced in the RMPP region, where wind penetration is the greatest as a percentage of baseline CEMS load. Third, less thermal capacity is needed in every market as a reflection of the fact that wind generation has lowered the residual demand required to be served by thermal sources. However, the equilibrium thermal capacity requirement is reduced only modestly by the entry of new wind capacity.

These factors are summarized in Table 5. For each region, the aggregate equilibrium thermal capacity and assumed wind capacity are given in the first two columns of figures. The assumed average capacity factor, taken from the wind profiles from the WECC study is given in the next column, and the shares of thermal capacity that are base load and peaking are given in the last two columns. Note that the large levels of new wind capacity, those of more than 10 gigawatts (GW), result in reductions of equilibrium thermal capacity of only 1 to 2 GW.

Table 5. Equilibrium results for energy-only market

	Thermal Capacity (MW)	New wind Capacity (MW)	Wind capacity factor	Share Coal	Share CT
	23,308	NA	NA	43%	44%
CA	22,753	5,670	33%	36%	50%
	22,442	11,340	33%	28%	55%
	14,472	NA	NA	93%	0%
NWPP	13,188	7,890	28%	81%	4%
	12,237	15,780	28%	64%	10%
	20,276	NA	NA	73%	11%
AZNM	19,691	3,840	39%	68%	14%
	19,141	7,680	39%	62%	17%
	6,751	NA	NA	86%	7%
RMPP	6,000	4,650	41%	61%	20%
	5,374	9,300	41%	26%	37%

Across the regions, the reduction in thermal capacity averages about 15% of the new installed wind capacity, with relatively little variation across regions. It is important to mention again, however, the strong assumption made here that hydro output, particularly in the NWPP region, would not adjust to the new intermittent capacity. By taking advantage of the implicit storage potential of the hydro resources, one would expect the equilibrium capacity needs in this region to be reduced quite a bit more than implied by this calculation.

5.2 Capacity Market Results

As in the appendix, the simulation of a capacity market requires two important parameters to be specified. The first is the energy market price cap, set here to be $1,000/MWh. The second important parameter is the capacity market payment made to the generation sources. In order to calculate the capacity payment, the implied shortfall that would be created by capping prices at $1,000/MWh is first estimated.[4]

In practice, capacity payments are intended to replace the revenues necessary for investment that are in principle denied to suppliers through either explicit or implicit restraints on energy prices (see Joskow 2005; Oren 2005). For this study, this was accomplished by calculating the total revenues of peaking generation sources under the energy-only scenarios described above. Next, a counterfactual level of income for a 1 MW peaking generator that would have resulted from the same investment levels is calculated, but with prices earned by generators capped at $1,000. The difference, sometimes known in industry jargon as the "missing money" caused by price caps, can be expressed as a dollars-per-kilowatt-year ($/kWy) value. This value was used as the capacity payment in the second set of simulations. These payments are summarized in Table 6.

Table 6. Capacity payments resulting from $1,000 price cap (in $/kWy)

	No new wind	14% of CEMS	28% of CEMS
CA	58.41	54.58	55.84
NWPP	0.00	0.00	0.00
AZNM	1.15	1.57	12.06
RMPP	0.00	2.53	24.80

It is worth noting that these values are quite a bit lower than those currently seen in U.S. electricity markets. One reason for this is that the investment numbers from the EIA represent generic investment costs for the country, while capacity markets tend to operate in regions of the United States, such as California and New York, where investment can be much more costly. Another more important driver is that these equilibrium simulations are allowing the price to rise above the marginal cost of a peaking plant more frequently than has been historically seen in these markets. This is a reflection of the fact that the model determines the equilibrium, break-even level of capacity, whereas today's markets tend to feature more capacity than this level. In practice, today's capacity markets do not attempt to differentiate among causes of revenue shortfalls; they usually calculate net costs of entry based on historic energy prices.[5] Therefore, the revenues lost to the price cap in this simulation produce less missing money than has been estimated from current capacity market proceedings.

Next, the above simulations are repeated, with two adjustments to the original model summarized by equations (4) and (5) in the appendix at the end of this chapter. The most striking results are naturally found in the hours that were formally those with prices significantly above \$1,000. Figures 8 and 9 illustrate the changes to the peak hour price duration curves for the CA and RMPP regions because of both wind penetration and the capacity market policies. These figures summarize the 150 highest price hours in each market, in order from highest to lowest. Note that prices in these figures are on a logarithmic scale because of the high volatility.

Figure 8. Highest 150 prices CA

[INSERT FIGURE 8 HERE]

Figure 9. Highest 150 prices RMPP

[INSERT FIGURE 9 HERE]

For the wind scenarios, the same hours are plotted. As is clear from these figures, the highest price hours in the baseline simulations are not those producing the highest prices as wind investment increases. This reflects that fact that as wind investment increases, prices are increasingly driven by wind availability as well as total end-use demand. This is particularly true for the RMPP region, where the highest price hours under high levels of wind investment rank below the 100th highest price hours without the wind investment. These figures also illustrate the impact that the price cap has on these "scarcity price" hours. In general, the highest price hours are reduced to the cap levels, and price levels in most other hours remain unchanged. The impact of these capacity market elements on investment levels are summarized in Table 7.

Table 7. Investment Levels with a Capacity Market

	Thermal Capacity (MW)	New wind Capacity (MW)	Wind capacity factor	Share coal	Share CT
	23,421	N/A	N/A	43%	44%
CA	23,141	5,670	33%	36%	50%
	22,817	11,340	33%	28%	55%
	14,472	N/A	N/A	93%	0%
NWPP	13,188	7,890	28%	81%	4%
	12,237	15,780	28%	64%	10%
	20,282	N/A	N/A	73%	11%
AZNM	19,691	3,840	39%	68%	14%
	19,168	7,680	39%	62%	17%
	6,751	N/A	NA	86%	7%
RMPP	6,001	4,650	41%	61%	20%
	5,383	9,300	41%	26%	37%

Note: MW = megawatts.

5.3 Revenues of Wind Resources

Because individual wind plants will have varying profiles across and within regions, it is difficult to make general statements about the equilibrium revenues of wind plants. Nevertheless, the earnings are estimated of a hypothetical 1 MW "portfolio" of plants that features the same production profile as the regional aggregate profile used to construct the residual demand.

In order to evaluate the revenues of intermittent resources under a capacity market paradigm, further assumptions are needed about how the reliable capacity of those resources, on which the capacity payment is based, is measured. The most basic, and clearly overgenerous, method would be to assume that 100% of the installed capacity was eligible for capacity payments. Given the intermittent availability of wind resources, this is not the usual approach. A more conventional approach is to discount the installed capacity according to a historical measure of the capacity factor (average energy output divided by capacity) of either the specific unit or the class of technologies from which the unit is drawn. Even this approach can overstate the "value" of capacity if the production profile of a generation unit is negatively correlated with total system load. A third approach, similar to one recently adopted for the purposes of measuring wind and solar capacity in California, is to measure the production of resources only during high demand hours, discarding production statistics for other hours.[6]

For purposes of comparison, revenues have been calculated under a capacity market in two ways, roughly following the options outlined above. The first approach discounts the capacity payment according to the annual capacity factor, derived from the wind profile data. The second approach calculates a capacity factor only for hours 14 through 17 of each day. The results for the two alternative calculations of capacity factor (using annual average and peak hour average) were very similar, so only the revenues are reported, assuming capacity payments are based on the peak hour average capacity factor.

Table 8 summarizes the revenues of this hypothetical average wind turbine for each region. These values are given in terms of $/kWy. By comparison, the peaking units are earning $95.82/kWy, while coal plants are earning $282.17/kWy.[7] To the extent that actual costs of new wind facilities would exceed these equilibrium investment revenue levels, the difference would have to be captured in subsidies—either through the production tax credit or through price premiums paid by utilities in order to comply with their renewable portfolio standards. As further reference, using the same assumptions and cost estimates from the EIA as were used to calculate thermal annual fixed costs, wind costs would be roughly $231/kWy.

Note that under the energy-only market, the revenues for an average profile wind plant decline in each region. This is because prices are being influenced increasingly by wind availability, and a profile that mirrors the system wind profile would be producing during hours of glut and not producing during hours of wind production shortfall. If revenues are instead based on a combination of capped energy market revenues and capacity payments, wind producers do a little better than under the energy-only paradigm. This is a much stronger effect under the high wind penetration scenarios.[8] Revenues in the RMPP area are about 5% higher with a capacity payment. This is in part because the capacity payment rewards production during high *demand* hours, whereas the energy-only market rewards production during high *price* hours. As wind penetration increases, the high price hours are relatively more focused on low wind hours than on high demand hours.

Table 8. Summary of the revenues of the hypothetical "average" wind turbine ($/kWy)

		Energy-only	
Region	CEMS load	New wind 14% of CEMS	New wind 28% of CEMS
CA	113.24	112.11	109.27
NWPP	123.49	106.48	105.17
AZNM	138.31	135.00	132.75
RMPP	158.39	142.03	135.17

		Capacity Market	
Region	**CEMS load**	**New Wind 14% of CEMS**	**New Wind 28% of CEMS**
CA	126.74	124.82	122.31
NWPP	123.49	106.48	105.17
AZNM	138.35	135.59	136.27
RMPP	158.39	143.02	144.36

5.4 Impact of a Carbon Market

The last scenario examined is the application of a price of CO_2 onto the electricity sector. For the purposes of this discussion, the source of the CO_2 price could be either a cap-and-trade mechanism or a CO_2 tax. Rather than try to calculate a closed-loop equilibrium price for CO_2, it is assumed that these regions participate in broader CO_2 markets with a price of $25/ton. This value is approximately the 2012 futures price for one ton in the European Union's Emissions Trading System (ETS) market for CO_2. It is also assumed that the imposition of CO_2 prices affects only marginal and not capital or fixed costs of any of the thermal generation technologies. The same approach as before can be used to calculate the resulting equilibrium investment levels of thermal capacity and revenues for wind facilities. Only the equilibrium is calculated under the energy-only market paradigm. Figure 10 illustrates the equilibrium investment capacities under the different wind scenarios. Note that coal is much less used in all markets and is driven out of the CA and RMPP markets completely under high wind penetration.

Figure 10. Equilibrium capacity investment with $25/ton CO_2

[INSERT FIGURE 10.10 HERE]

Table 9 summarizes the energy market revenues earned by the hypothetical wind plant under various levels of wind penetration. With the $25/ton carbon price, wind revenues are substantially higher overall. The degradation of these revenues with increasing wind penetration is also more pronounced, however. With a price on CO_2, revenues in the RMPP region are only 5% lower per kilowatt-year under high wind penetration than they would be for the first megawatt of wind capacity added to that region. This is contrasted to the almost 15% decline in revenues for the same comparison in the absence of a carbon market. With carbon at $25/ton, wind resources are able to earn relatively more revenues during even off-peak hours when coal would be setting the price. Increasing wind penetration leads to more of these hours, but the differential between these off-peak and on-peak hours is smaller than in the absence of a carbon price.

Table 9. Wind revenues with carbon price at $25/ton (in $/kWy)

Region	CEMS load	New wind 14% of CEMS	New wind 28% of CEMS
CA	194.15	193.00	185.29
NWPP	188.06	173.46	172.81
AZNM	231.09	228.41	227.96
RMPP	251.85	246.10	238.87

5.5 Estimating the Cost of Energy Availability Profiles

Given that the equilibrium mix of generation resources can be quite different with high penetration of wind resources, it is natural to ask what the costs impacts of this changing mix might be. This question is addressed by comparing two hypothetical scenarios. First the total and average costs of serving the *residual* demand (e.g., that which is left over after the new energy is applied) are calculated under the assumption that new energy appears in a manner consistent with the two wind penetration scenarios described above. In other words, the average cost of constructing and operating thermal plants to meet the demand that is not met by the renewable production is calculated. Second, the same amount of energy is used as in the wind scenarios, but instead assuming that it is applied as a base load supply source. In other words the “new” energy is distributed evenly across all hours.

The results of this calculation are summarized in Table 10. The columns labeled "As wind" refer to the same wind distributions that have been applied to previous results, and those labeled "as base load" show the results for the evenly distributed energy. Because the more volatile wind profiles require the construction of fewer base load plants and less frequent operation of peaking plants, average costs are higher under the wind profiles. In California, average costs from the variability of supply increase about 4% ($3/MWh) under 14% wind penetration and close to 9% ($7/MWh) with high wind penetration. In the high-penetration RMPP region, costs rise close to 25% under the high-wind-penetration scenario.

Table 10. Impact of Intermittancy on Average Thermal Costs ($/MWh)

	New energy 14% of CEMS load		New energy 28% of CEMS load	
	As base load	As wind	As base load	As wind
California	75.73	78.61	81.87	88.92
NWPP	57.70	59.20	59.02	63.56
AZNM	59.89	61.05	60.71	63.37
RMPP	57.71	63.09	62.28	85.11
		With carbon at $25/ton		
California	100.26	102.78	106.46	107.18
NWPP	82.16	83.57	83.15	87.31
AZNM	84.82	85.76	85.56	87.61
RMPP	83.43	88.20	88.43	104.92

6. Conclusions

The increasing deployment of renewable resources whose intermittent production is determined by natural forces will reshape the economics of power generation in developed electricity markets. This chapter has presented calculations on what the optimal mix of major conventional generation sources would be under various assumptions of end-use demand and penetration of wind generation. Data on actual demand for thermal generation in the western United States were combined with highly detailed estimates of production from new wind resources for this region of the country. The result is a load shape with relatively higher spreads between peak and average demand for thermal production. As demonstrated in the equilibrium model, the amount of coal-fired base load production that would be an economical equilibrium investment steadily declines as wind penetration increases. The reliance on the low-capital-cost combustion turbine technology increases.

Another key change in the economics of power systems will come from the rising importance of intermittent production as a driver of market prices. As these simulations demonstrate, the availability (or lack) of wind resources will be an important contributor to market clearing prices. The normal relationship between end-use demand levels and market prices becomes redefined as wind resources grow to take a substantial share of the market. Implications of this are that wind resources that are “typical,” in the sense that their output is correlated with the bulk of other wind resources, will earn less, and the total capacity of wind resources is ramped up. Their production will be correlated with hours of surplus and therefore increasingly less correlated with prices. In the presence of a capacity market, this effect is more muted. This is because capacity markets—at least at present—award capacity payments based on availability during high-demand periods, rather than high-price periods. This too may change, however, as the underlying economics of the energy markets become more strongly influenced by the ebbs and flows of intermittent generation.

Overall, increasing reliance on intermittent resources creates, or increases, costs in a fashion similar to that caused by fluctuating end-use demand. In planning to serve a system where consumption fluctuates widely, firms must turn to resources that are more flexible, but also more expensive on an average cost basis. While the added costs associated with fluctuating end-use demand can be greatly mitigated by enabling price-responsive consumption, the intermittency of renewable supply is a fact of nature. Storage technologies can play a valuable role here, and estimates such as those developed in this chapter can provide an indication of the potential value of such storage options.

Although the analysis in this chapter was grounded in data taken from actual energy markets, it is important to recognize the limitations of this exercise. Two important elements of some electricity markets are missing here, although their effects work in opposite directions. The short-term operational constraints of thermal generation units have not been modeled. The presence of such constraints would tend to favor the nimble combustion turbine technology even more heavily. Also not modeled is the potential reallocation of production from energy-limited resources, namely hydroelectric. In the Pacific Northwest in particular, this will be an important resource that can go a long way toward counteracting the effects of intermittent generation. In fact, even with these limitations, the effects of wind penetration in the NWPP region are relatively minor in contrast to the wind-rich but hydro-poor Rocky Mountain region. The potential for increased trade among the regions also has not been modeled, although such trade will be limited by the availability of transmission capacity.

Of course, the real western United States is not starting from scratch in building its investment portfolios. Outside of California, coal-fired generation is a currently a mainstay of electric companies west of the Mississippi. To the extent that these results portend changes in the economics of these technologies, they would affect the earnings of the owners of these technologies more than the actual mix of generation resources.

Appendix: An Equilibrium Model of Generation Investment

This appendix describes the technical derivation of the equilibrium investment model employed for the results presented above. Each conventional generation technology, indexed by i, features a marginal cost c_i and fixed cost of capacity F_i. Firms invest in capacity that serves a market with demand that fluctuates over time periods $t \in (1 \ldots T)$ with some degree of price elasticity. Demand at time period $Q_t(p_t)$ is represented as

$$Q_t(p_t) = a_t - f(p_t)$$

where a_t is an additive shift of demand and $f(p_t)$ is a function of market price p_t.

The perfectly competitive firms in the model continue to add production in any given hour, and capacity overall, as long as the revenues from adding the production or capacity exceed the costs. In equilibrium, therefore, production levels in any hour will be set such that the marginal cost of production equals the market price. This equilibrium point can be represented with the following complementarity condition:

$$q_{it} \geq 0 \perp p_t - c_i - \psi_{it} \leq 0 \; \forall \text{ i, t} \qquad (1)$$

where ψ_{it} represents the equilibrium shadow value of the capacity of technology i and will never be positive if price is below marginal costs c_i. This is the shadow price on the constraint that production be no greater than installed capacity, as reflected in the following condition:

$$\psi_{it} \geq 0 \perp q_{i\,t} - K_i \leq 0 \;\forall\; \text{i, t} \qquad (2)$$

Equation (1) is therefore equivalent to setting price equal to marginal operating costs as long as production quantities are below the capacity constraint K_i. The equilibrium level of investment will arise from the condition that the value of a marginal unit of capacity equals the cost of that capacity.

$$K_i \geq 0 \perp F_i - \sum_t \psi_{it} \leq 0 \;\forall\; \text{i} \qquad (3)$$

where $\sum_t \psi_{it}$ represents the cumulative value of an extra unit of capacity type *i* aggregated over all time periods. Recall that this value is zero for a given period if the capacity is unneeded in that period, which in this model is equivalent to prices falling below the marginal cost of production of technology *i*.

The equilibrium level of investment and production can be found by simultaneously solving for the above three conditions. These conditions form a complementarity problem (see Cottle et al. 1992) of size $t \times i$. The following sections describe the data used in formulating the empirical model.

Market Demand

Demand is represented with the partial-log function

$$Q_{rt}\,(p_{rt}) = a_{rt} - b_r \ln(p_{rt})$$

where r is used to denote the region. The value for b was set at 800 for CA, NWPP, and AZNM, and a value of 400 was used for the smaller RMPA. The price elasticity for this functional form of demand is equal to b_r/Q_r, so at the mean observed demand level (summarized in Table 1), elasticity is about 0.05 in each market. In other words, a nonzero but still very modest level of demand response is assumed. One advantage of this functional form of demand is that its convexity implies little price response at levels around the marginal costs of generation, but more response when prices reach "scarcity" levels over $500/MWh.

Price Caps and Capacity Payments

The above modeling framework imposes two significant assumptions to reach its equilibrium. First, at least some degree of price response from end-use demand is assumed. Second, equilibrium energy prices are not constrained in any way and are allowed to rise in order to balance supply and demand.

In modeling a stylized capacity market, the above model is modified in several ways. First, the price cap is represented with the addition of a large capacity "fringe" technology with a marginal cost of $1,000/MWh. In other words, in addition to actual thermal technologies, i, there is an additional complementarity condition similar to equation (1) without the capacity constraint on production:

$$q_{CAPt} \geq 0 \perp c_{CAP} - p_t \leq 0 \;\forall\, t \qquad (4)$$

where q_{CAPt} is positive only if the price cap level c_{CAP} is binding. The quantity q_{CAPt} can be thought of as the energy shortfall caused by the price cap, to be dealt with through either demand rationing or out-of-market transactions. To allow for capacity payments, equation (3) is modified so that the annual fixed costs of entry equal energy market revenues *plus* the capacity payment:

$$K_i \geq 0 \perp F_i - \text{CAP\_PAY} - \sum_t \psi_{it} \leq 0 \qquad (5)$$

The capacity market equilibrium is therefore represented by the simultaneous solution of conditions (1), (2), (4), and (5).

Revenues to Wind Producers

Earnings of the average wind profile are calculated by multiplying the output of wind production by the market price for each period. In other words, the energy market earnings of such a portfolio can be expressed as

$$\sum_t p_{rt} * \mathrm{CF}_{\mathrm{rt}} * \mathrm{Capacity}_{\mathrm{r}} \qquad (6)$$

where CF refers to the capacity factor of wind in region *r* at time *t.*

Notes

1. Private Independent Power Producers (IPPs) own 83% of cumulative wind capacity in the United States (Wiser and Bolinger 2009). The passage of the Emergency Economic Stabilization Act in November 2008 could constitute a major shift in this trend. Among the act's many provisions was the extension of investment tax credit (ITC) for certain forms of renewable generation. The act also allows, for the first time, utility companies to take advantage of the ITC, which had previously been reserved only for nonutility producers.

2. The CEMS data are available at www.epa.gov/cems. The Platts datasets, POWERDAT and BASECASE, are available via paid subscription service at www.platts.com.

3. The study assumes a 15% total renewable penetration, but only half of that is estimated to come from wind. However, in 2007, about half of the existing energy currently generated in the WECC came from non-CEMS sources. So the wind portion of our residual demand profiles is roughly 7.5% of total load in the base case, and 15% under the assumption of doubled wind capacity.

4. The mechanisms and levels for limiting prices varies by market. Markets in the eastern U.S. technically limit offer prices to $1,000/MWh. In theory market clearing prices can rise above this level, but they have not in practice done so. One hypothesis (Joskow 2005) is that actions taken by operators to preserve reliability also coincidently limit prices below "scarcity" levels required to recoup investment costs.

5. An example of such a calculation for the New York ISO region can be found in NERA (2007).

6. The newly adopted California rule also uses an *exceedance* measure, rather than a capacity factor. This means that the capacity payment is based on the percentage of peak hours in which production exceeds a given threshold (e.g., 70%) of nameplate capacity. Using the data in this discussion, this measure gave extreme results, so instead the focus here is on a measure of peak hour capacity factor.

7. Recall that these are their annual entry costs, and the equilibrium conditions equilibrate net operating costs with these annual fixed costs.

8. The $1,000/MWh price cap was almost never binding in the NWPP and AZNM regions; therefore, the results for the energy-only market and capacity markets are virtually the same. These markets have no "missing money," and thus no capacity payment was necessary even with the price cap in place.

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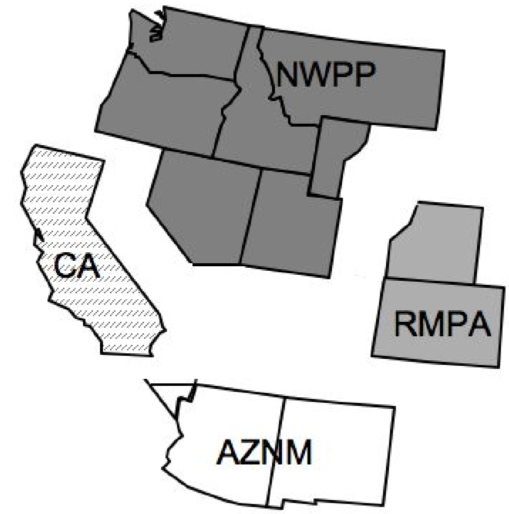

Figure 1: WECC Subregions

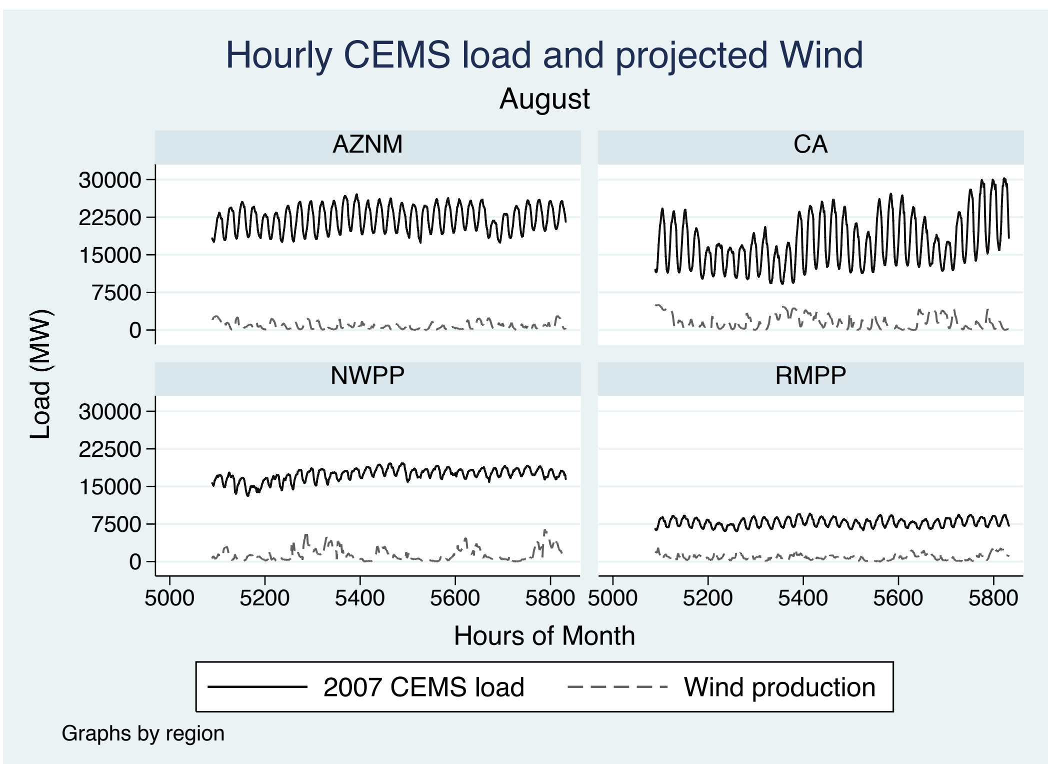

Figure 2: CEMS Load and Wind Production for July

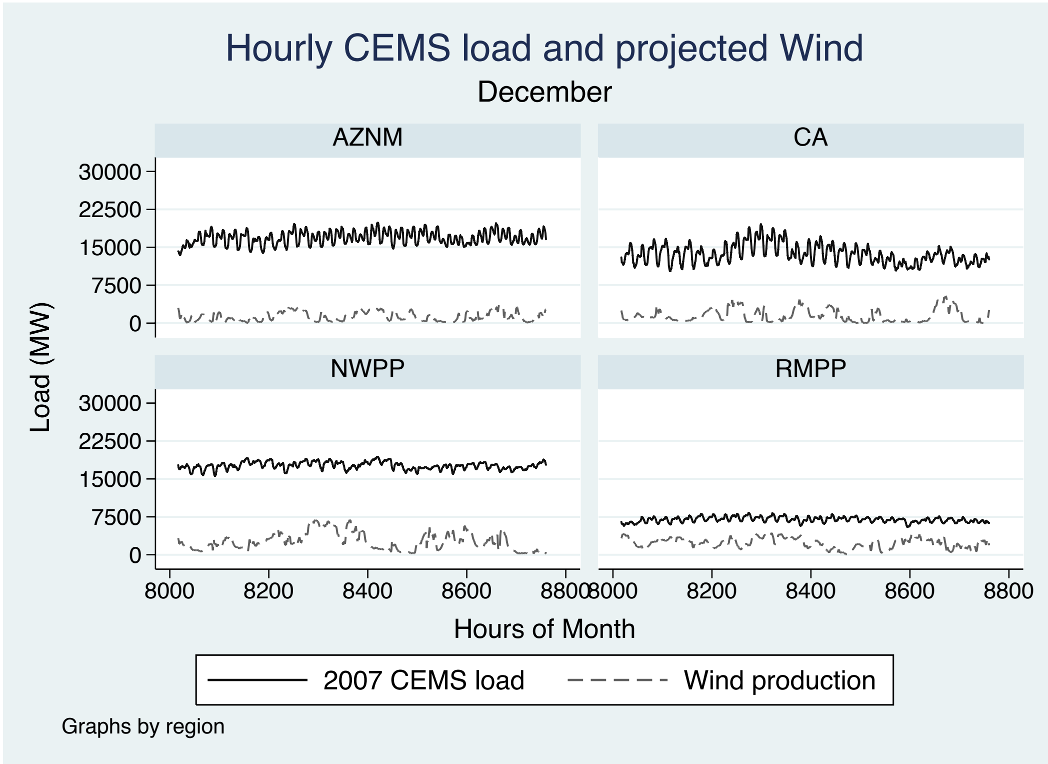

Figure 3: CEMS Load and Wind Production for December

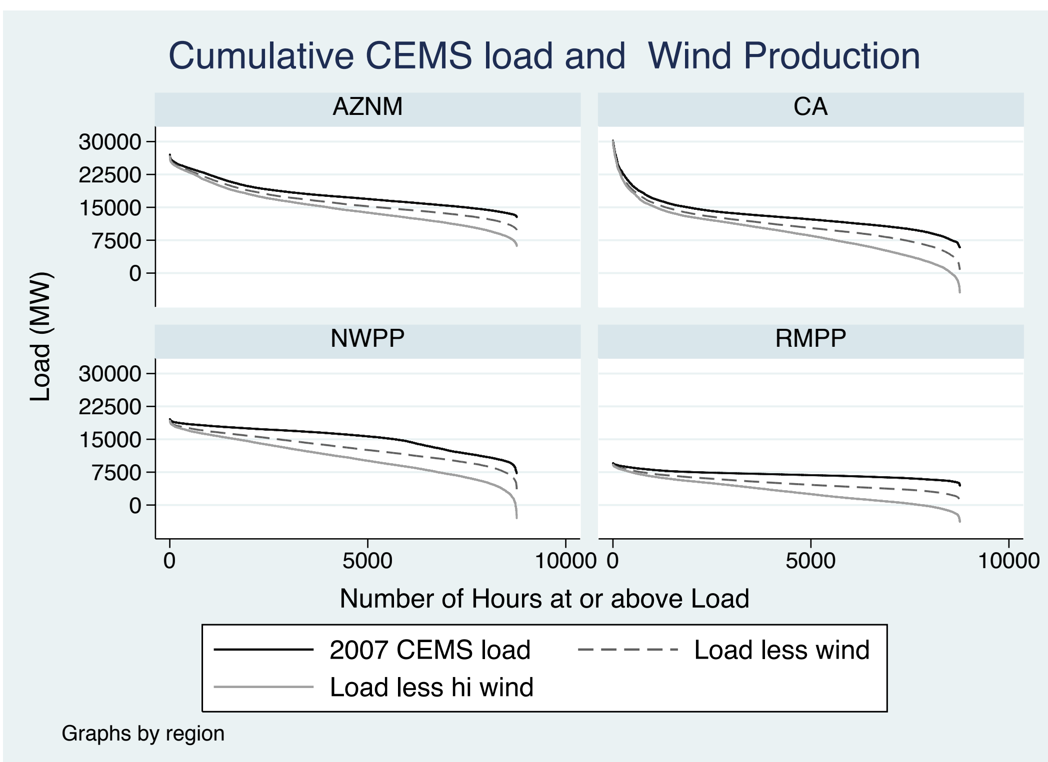

Figure 4: Annual Distribution of CEMS Load net of Wind

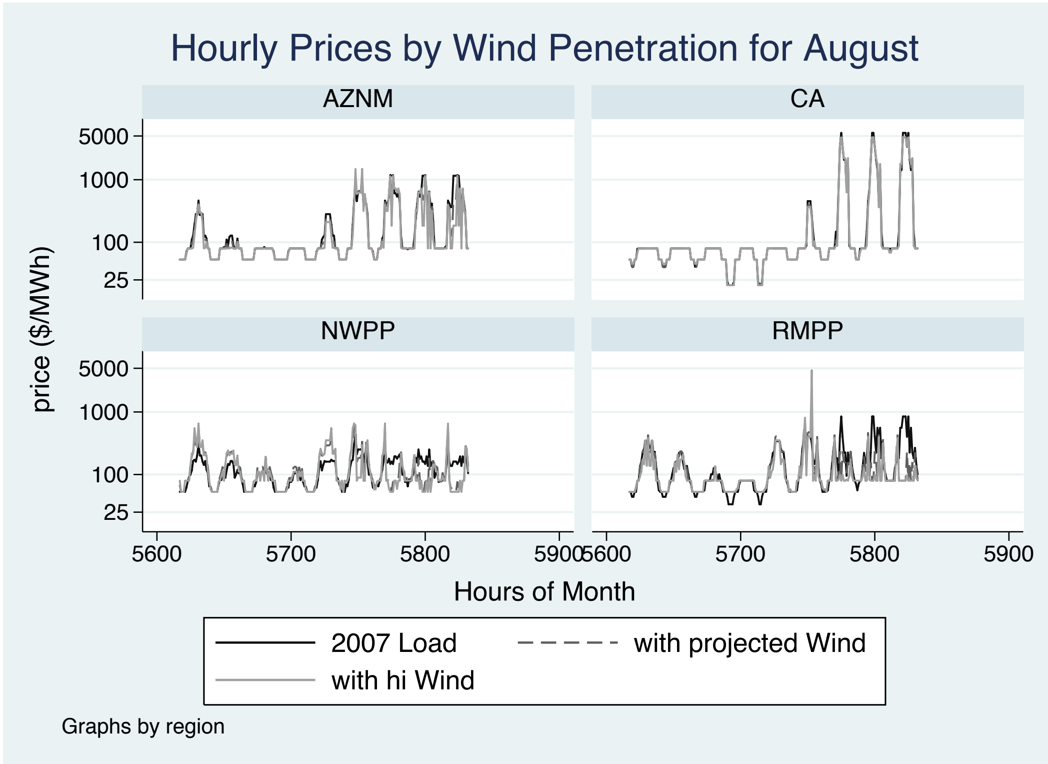

Figure 5: Energy Market Prices for July

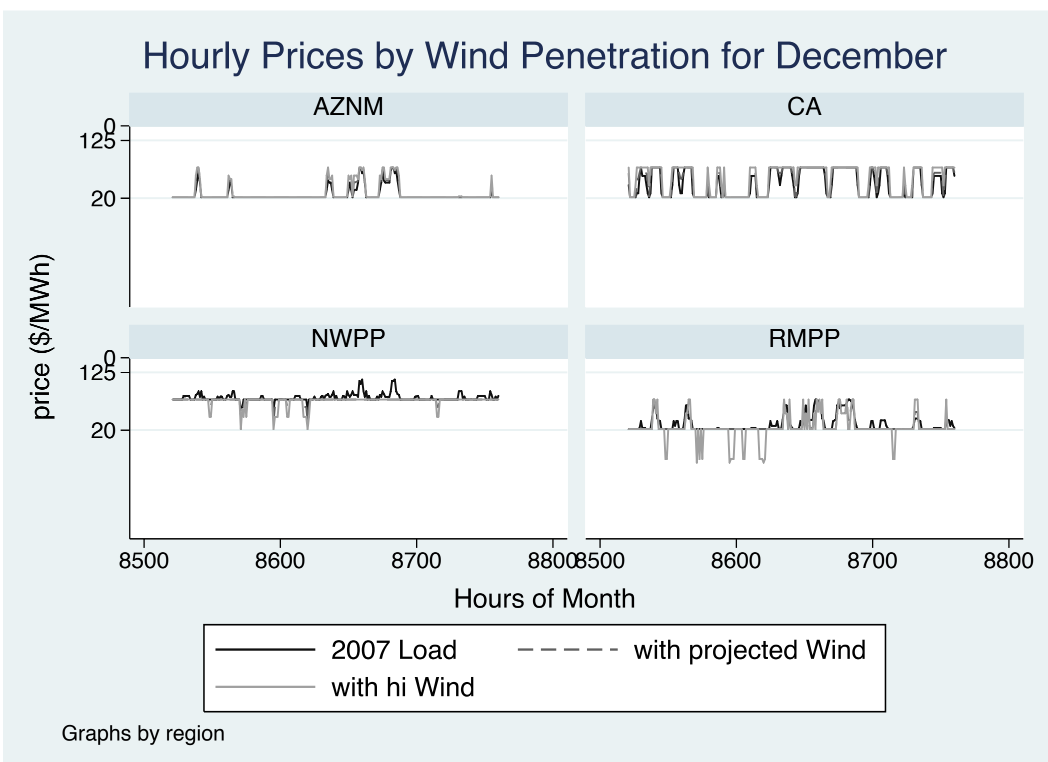

Figure 6: Energy Market Prices for December

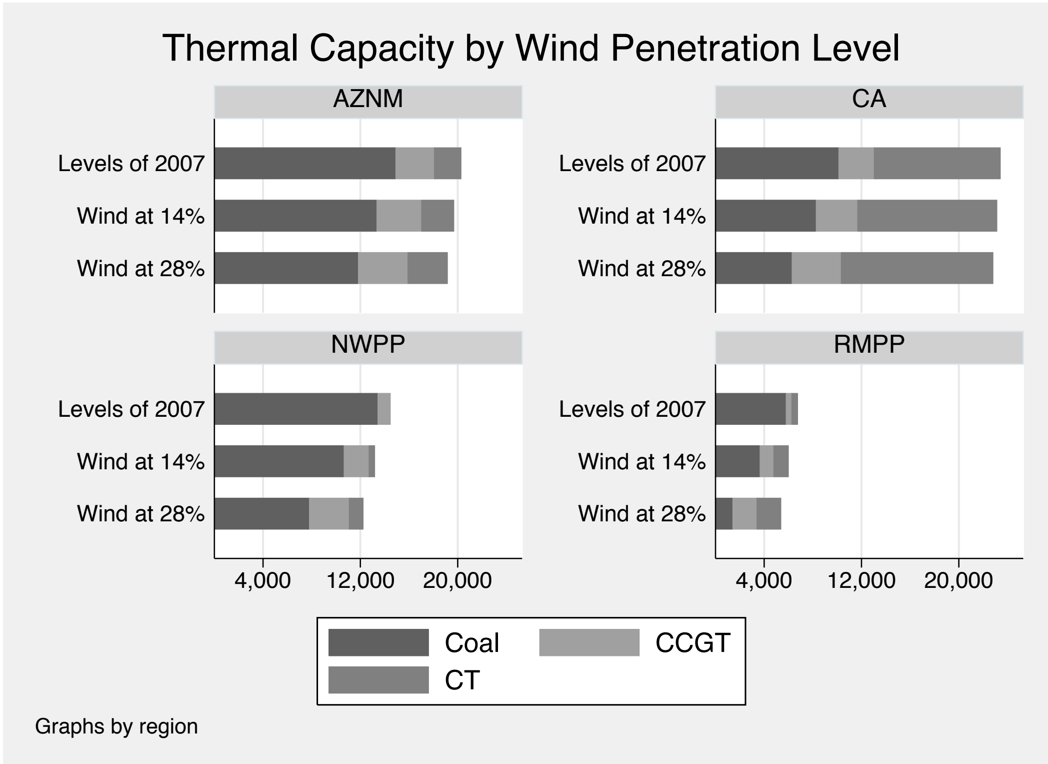

Figure 7: Equilibrium Capacity for Energy Only Market

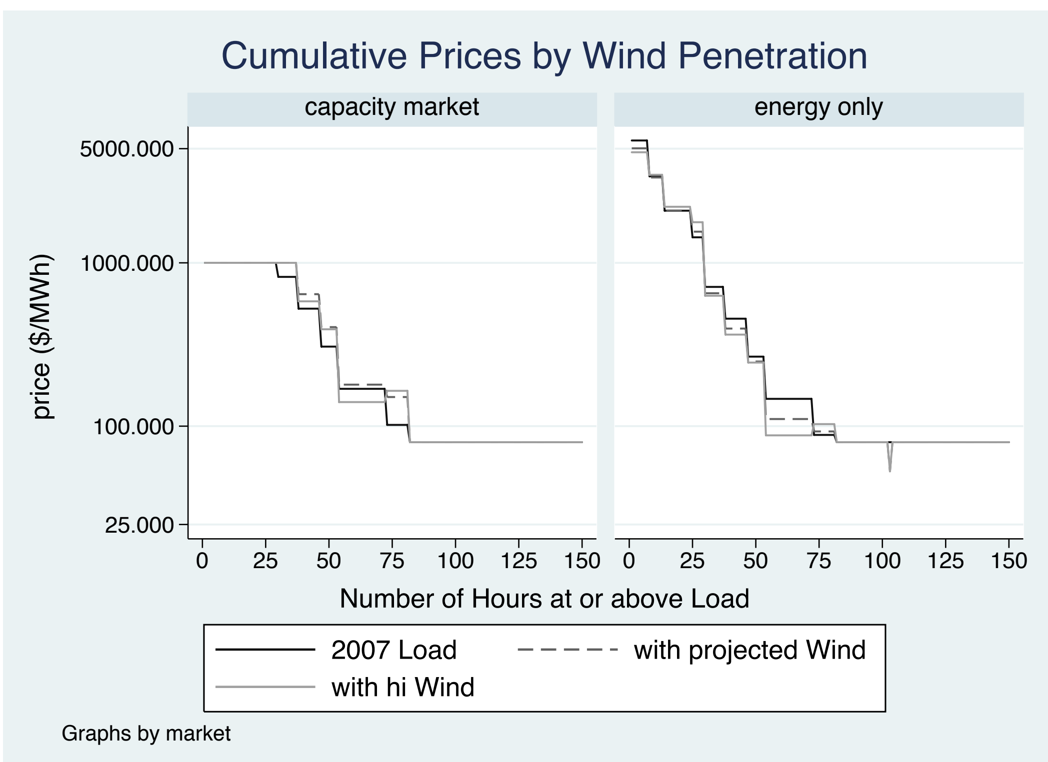

Figure 8: Highest 150 prices CA

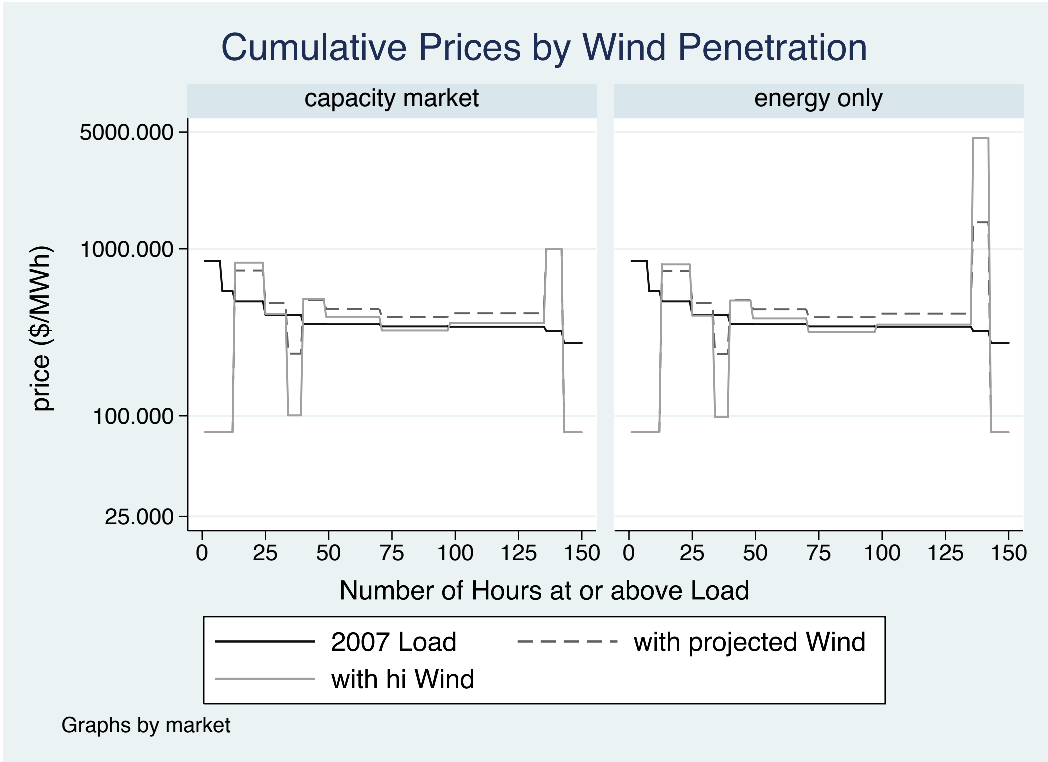

Figure 9: Highest 150 prices RMPP

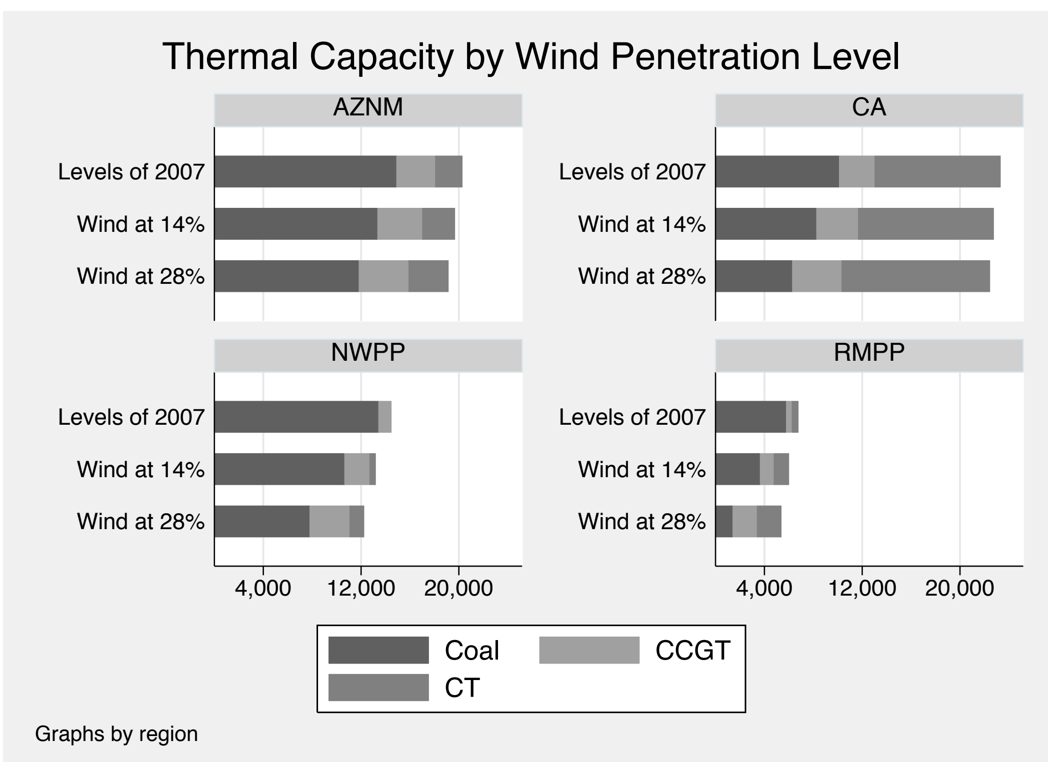

Figure 10: Equilibrium Capacity Investment with $25/ton CO2